ANALYSIS AND EVALUATION

of the

INTEGRATED RESOURCE PLANS

of the

INVESTOR-OWNED AND STATE-OWNED

ELECTRIC UTILITIES IN SOUTH CAROLINA

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The South Carolina State Energy Office

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I. Executive Summary

A. Introduction

The purpose of this report is to present an analysis and evaluation of the Integrated Resource Plans (IRPs) filed by the South Carolina investor-owned and state-owned electric utilities, to compare and contrast the IRPs both locally and nationally, to develop recommendations for improvements in the IRPs and to discuss the future of the IRP process in South Carolina, given the movement towards deregulation of the electric industry.

As part of the South Carolina Energy Conservation and Efficiency Act of 1992, each investor-owned and state-owned electric utility operating in South Carolina is required to file an IRP every three years and supplement the IRP with Short-Term Action Plans (STAPs) each year between full filings. The IRPs are to be submitted to the South Carolina Public Service Commission and the South Carolina State Energy Office. Filing requirements for the IRPs and STAPs were developed by the South Carolina Public Service Commission. In practice, there is no formal IRP approval process. However, the IRP filings provide extremely important information to ratepayers and regulators concerning the plans of the South Carolina electric utilities to meet the state's future needs for electricity.

The following five utilities operate in the State of South Carolina and are required to file IRPs:

- Carolina Power & Light Company (CP&L)
- Duke Power Company
- Lockhart Power Company
- South Carolina Electric & Gas (SCE&G)
- Santee Cooper

All of the utilities except for Santee Cooper are investor-owned.[1] Santee Cooper is a state-owned electric utility.

Lockhart Power is a small utility that purchases the majority of its electrical requirements from Duke Power, and thus does not play a large role in South Carolina's electric future. This report concentrates on the four remaining utilities. Each of these utilities filed either a full 1994 or 1995 IRP followed by at least two STAPs. This report is based upon these IRPs and the subsequent STAPs.

An IRP is essentially the utility's plan to meet the future electric needs of its customers in a way that considers environmental impacts along with the concerns of customers, regulators and stockholders. Within the IRP, selection of ways to reduce, or

[1] Santee Cooper is also known as the South Carolina Public Service Authority

shift electric usage (demand-side resources) are weighed in an equitable fashion against ways to increase the production of electricity (supply-side resources). The bottom line of an IRP is a schedule of demand-side and supply-side resources that will provide for the continued reliable delivery of electricity to all customers in South Carolina.

It is important to consider this document in light of two realities facing the current utility industry. First, utilities in the State of South Carolina currently operate as regulated monopolies, and as such, they have a long history of working within the framework of public and regulatory scrutiny. This evaluation looks closely at the quality of the IRP analyses and reports, to see if the companies have met reasonable standards expected of regulated electric utilities in planning for their resource needs. Until legislation is passed and a transition to a deregulated environment has been achieved, utilities will continue to operate within the confines and obligations of a regulated utility industry.

The second reality is that the utility industry is being transformed. Competition at the wholesale level has been largely accomplished and most people in the industry believe it is just a matter of time before it will occur at the retail level. Legislation has already been introduced in South Carolina calling for the deregulation of the state utility industry, and the South Carolina Public Service Commission has put forth a plan to deregulate the industry. The utilities are planning for the transformation, despite their public outcries against retail competition. This evaluation addresses this second reality by considering ways in which the State of South Carolina can still address some of the most important issues associated with Integrated Resource Planning in a deregulated environment.

B. Major Findings

The analysis and evaluation of the IRPs and STAPs, described in detail in the later sections of this report, resulted in the following major findings:

1. The IRPs and STAPs filed by the South Carolina utilities collectively represent reasonable analyses using sound planning methods. This is especially apparent when comparing the South Carolina IRPs to those filed by utilities in other states. Nevertheless, the IRPs filed by the South Carolina utilities could still stand some improvement.

2. The IRPs and STAPs filed by the South Carolina utilities do not provide complete or consistent information to allow for the uniform evaluation of the utility IRPs.

3. The lack of a requirement for approval of the IRPs calls into question whether the full benefits of the IRP process are being realized.

4. There exists a great deal of inconsistency among the utilities concerning the potential resources (both demand-side and supply-side) that are considered.

5. Although several utilities consider the consequences of a carbon tax, the utilities do not fully consider what combination of environmental costs and benefits would result in alternative resources and Demand-Side Management (DSM) programs becoming more cost effective. Nor do the utilities present plans that reflect the monetization of environmental externalities, as required by the IRP rules.[2]

6. Information concerning the complete environmental impacts of the IRPs is not consistently provided. When the original IRPs were written in 1995, many of the current environmental issues were only starting to appear on the radar screen. However, little updating regarding the environmental issues appears in the subsequent STAPs.

7. The demand-side achievements of Duke, SCE&G and Santee Cooper fall well short of the average achievements nationally.

8. The utilities express concern about DSM programs that cause rates to go up, and yet they ignore DSM programs that clearly have positive rate impacts.

9. Although future resource additions in South Carolina will be dominated by gas fired capacity, little consideration is given to the requirements for increasing the gas infrastructure necessary to meet the growing gas demand.

10. The utilities in South Carolina collectively show little interest in any sort of alternative energy resources or green pricing programs.

11. Under the assumption that the present utility industry structure continues, and even during the transition to deregulation, the current IRP process provides essential information to the ratepayers and regulators of South Carolina, and should continue. Furthermore, specific improvements, as described in Section VI, will bring additional value to the IRP process.

C. The Future of IRP

Across the country, more states are moving towards full deregulation of the electric industry. As stated previously, recent discussions may soon lead to electric deregulation in South Carolina. Although the IRP process, as it is defined today, would be inappropriate under full deregulation, it is unclear that a deregulated power market will provide the same level of electric reliability that customers now enjoy. To ensure this continued reliability and also to address other public policy issues that are currently considered as part of the IRP process, such as environmental impacts and DSM programs, it is recommended that a statewide IRP process (performed by the South

[2] Environmental externalities are costs to society resulting from emissions from utility power plants. Monetization is a process of quantifying these costs in dollars terms. When used in an IRP study, these costs serve to increase the total cost of resource plans that result in the production of emissions.

Carolina Public Service Commission working with the State Energy Office) be continued under full deregulation of the electric industry.

Significant issues will still need to be addressed under a deregulated environment. Load forecasting and issues associated with the adequacy of supply should still be considered. While it is extremely important to allow a free market to develop, it is also critical that proper reliability assessments be conducted to ensure that capacity additions are timed properly. Additionally, by giving the market the proper signals for timely capacity adjustments, a more competitive environment will develop.

Other considerations previously made within the context of an IRP process should still be evaluated (such as renewable technologies, research and development, DSM, energy efficiency, and others) and should be monitored by a state agency such as the State Energy Office. South Carolina lawmakers should consider requiring energy providers to disclose energy content information. This low cost option would result in more renewable energy being promoted in South Carolina. More than likely, energy suppliers will offer renewable energy as a marketing tool, and it will become necessary for an appropriate state agency to have oversight responsibility to ensure that suppliers do provide the energy from renewable resources as promised.

II. Integrated Resource Planning

A. Overview & History

The Integrated Resource Planning process was developed with three primary purposes in mind: (a) to provide an opportunity for public input and participation in the long-term planning processes of the utilities; (b) to cause utilities to evaluate demand-side resources and supply-side resources on an equal footing; and (c) to allow for the evaluation and consideration of the environmental impacts of the actions of the utilities.

Prior to the implementation of Integrated Resource Planning in the 1980's, electric utilities performed long-term planning in a vacuum – with little or no input from the public or regulatory bodies. During this period, the model for electric utilities was to capitalize on the economies of scale derived by building large central station plants. These large plants contributed to the falling real price of electricity that had been evolving for years since the Second World War. Because of the low prices for electricity, the public was encouraged to consume as much power as they cared to use, with little or no consideration for making efficient use of the energy. Utilities responded by initiating large power plant construction programs.

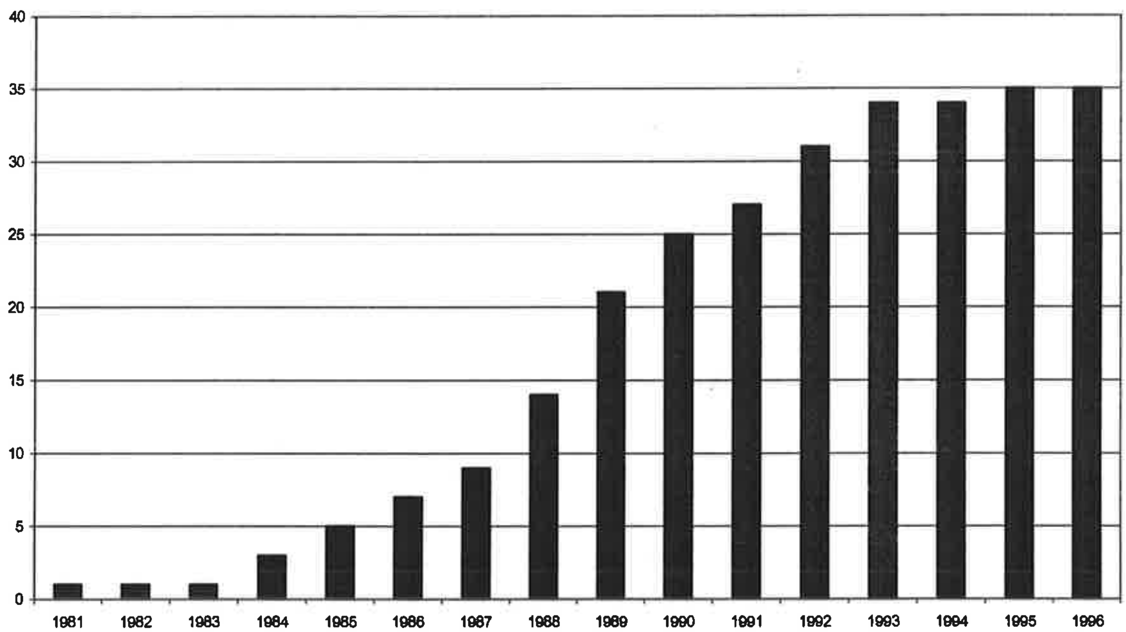
As a result of the boom in power plant construction, with very little public or regulatory oversight, the certification of new resources (generating plant) was often made after-the-fact, that is, after the construction of the generating plant was underway or even complete. This did not cause a major problem prior to the regulatory disallowance of the excessive costs of some nuclear generating plants. These nuclear disallowances were a major factor in the move to Integrated Resource Planning. With IRP, the utility could receive pre-approval for new generating plants prior to the initiation of construction and at the same time, the utility's customers could participate in the decision-making process.

The high cost of imported oil and the resulting uncertainty of the future price of oil in the 1970's, as a result of the Arab Oil Curtailments, also played a major role in the move to IRP. Rates for electricity were moving upward and regulators wanted to ensure that all options to meet the growing demand for electricity were fairly considered. Energy efficiency improvements were seen as a way to help lower costs and preserve precious energy resources. Although it is counter to the natural tendencies of electric utilities, the IRP process requires utilities to fairly consider DSM as a way to meet growing electric requirements. A DSM resource is a program that modifies the customer's need for electricity. An example is a program that encourages (through cash incentives) residential homeowners to add insulation to their homes. The added insulation reduces the use of air conditioning in the summer and electric heat in the winter, thus reducing the utility's need to generate electricity, and results in a more efficient use of electricity in the home.

The final major factor that resulted in the IRP process was the concern with the impact of generating plants on the environment. During the 1980's people became much more aware and concerned about the environmental impacts of pollution. Coal-fired plants are the main culprits, producing large emissions of sulfur dioxide (SO2), nitrous oxides (NOx), particulates, heavy metals, carbon dioxide (CO2), and other greenhouse gases. The Clean Air Act Amendments of 1990 resulted in national restrictions on the production of SO2 and NOx. Because of the recent worldwide summit in Kyoto Japan, nation-wide limits may be placed on the production of greenhouse gases. Through the IRP process, the levels of likely future emissions can be estimated and alternative plans that result in reduced emissions can be developed.

As shown in the following chart, the number of states that require electric utilities to file IRPs has grown steadily since 1981. Today 35 states require IRPs.

Number of States Requiring IRPs



Source - NARUC Compilation of Utility Regulatory Policy 1995-1996

The existing IRP process depends on the existence of the regulatory compact, in which the utility is allowed a territorial monopoly and rates for service are set through the regulatory process. With the movement toward retail competition underway, the regulatory compact is no longer a certainty. Numerous states now have legislation in place or are designing legislation to allow retail competition for electricity. Competition among utilities for retail customers means that the IRP process should be modified. Even though retail competition has not arrived in South Carolina, the South Carolina utilities are already concerned that revealing data through the IRP process could provide valuable information to competitors.

B. Basic Elements of an IRP

An IRP is the utility's long-term plan to meet the future electric needs of its customers. While each utility may perform an IRP study using different approaches, all IRP studies generally contain the following basic elements:

- Load Forecast
- Development of Initial Base Supply Plan
- Development of DSM Options
- Development of Supply-Side Options
- Integration Process
- Environmental Consequences
- Risk Analysis
- IRP Selection

The **Load Forecast** is the utility's estimate of the future electric requirements of its customers for at least 15 years into the future. It includes a forecast of the annual peak demand - the single highest hourly electric usage during the year and a forecast of the annual energy requirements - the total annual production of electricity required to meet the needs of all customers.

The next step in the IRP process is the **Development of the Initial Base Supply Plan.** The utility needs to develop an Initial Base Supply Plan as a reference plan for use in evaluating DSM options. To do this, a supply-side only optimization run is performed. The Initial Base Supply Plan, developed in this manner, is then used in the quantitative evaluation of DSM options.

The next step in the IRP process is the **Development of DSM Options**. In this step, the utility identifies all potential demand-side options that could be utilized to meet the future needs of its customers. Several qualitative and quantitative screenings are applied to the original list of options to produce a reasonable number of remaining options for inclusion in the Integration step. The screenings are usually based on a viability test and application of the California standard ratios – the Total Resource Cost (TRC) test, the Utility Cost Test, the Participant Test and the Rate Impact Measure (RIM) test. These ratios use fixed estimates of the costs that are typically avoided by DSM options to estimate the cost-effectiveness of the options.

The next step is the **Development of Supply-Side Options**. Here, just as in the previous step, a comprehensive catalog of potential supply-side options is developed and then screened for viability and cost-effectiveness. The normal screening process is a comparison of the total busbar costs of each of the viable options at various operating levels. Those options that have the best busbar costs are passed on to the **Integration Process**.

The **Integration Process** selects the "best" mix of DSM and supply-side options to meet the load forecast. "Best" may mean lowest total revenue requirements, least environmental impact, lowest customer bills, or some other measure selected by the utility. If environmental impacts are monetized in this step, then the resulting plan will minimize total costs that include capital, fuel, Operating & Maintenance expense (O&M), and environmental costs. It is generally accepted that the IRP should include several potential plans; for example, a plan that minimizes total revenue requirements, a plan that includes monetized environmental impacts and a plan that minimizes customer bills. This will allow customers and regulators to more fully understand how the costs, benefits, rates, environmental impacts, etc. are affected by different resource plans.

Environmental Consequences of each plan developed in the Integration Process should be included in the IRP. The annual production of all harmful emissions in each possible plan should be reported to provide customers and regulators information necessary for the proper evaluation of each plan. An assessment of environmental impacts should be performed even if environmental costs are not monetized as part of the Integration Process. Consideration should also be given to the impact of potential environmental legislation beginning to be discussed.

A **Risk Analysis** is normally utilized to ensure that the selected plan will perform well should assumptions change. For example, a risk analysis will identify the potential dollar risk inherent in the plan if actual fuel prices turn out to be dramatically different than what had been forecasted. Several types of risk analysis studies exist. The most frequently used types are Sensitivity Analysis and Scenario Analysis. Sensitivity Analysis is primarily concerned with determining how a particular expansion plan would be impacted by the change in a single variable (such as fuel costs). Scenario Analysis looks at the impacts on the selected expansion plan considering the possibility that future conditions might influence the change in more than one variable. For example, a higher load growth scenario might also suggest that fuel costs and capital costs would be higher due to higher rates of inflation.

Finally, the results of the **Integration Process** and the **Risk Analysis** are evaluated and the utility reaches a decision regarding its preferred IRP.

III. Comparing the South Carolina IRPs

A. Load Forecasts

1. Methodology

There are three basic methodologies available for load forecasting – Econometric, End-use and Trending. The econometric method uses regression techniques to forecast energy use and peak demand. A regression approach develops a series of equations that relate a desired output to a series of input variables. For example, energy sales can be the desired output and can be determined in an equation based on a relationship to other variables such as real disposable income, demographic data, weather patterns, etc.

End-use forecasting is a much more detailed load forecasting method, and is essentially a "bottoms-up" approach that builds up a total forecast from individual components such as the number of residential electric appliances in use. The advantage of end-use forecasting is that it provides valuable information that can be used in the analysis of DSM programs.

The last method, Trending, although popular in the past, is not widely used today. Trending simply develops a forecast from previous growth trends. The following table identifies the load forecasting methodologies employed by the utilities in South Carolina:

	Econometric	End-use	Trending
CP&L	Yes	Yes	No
Duke Power	Yes	Yes	No
Santee Cooper	Unknown	Unknown	Unknown
SCE&G	Yes	Unknown	No

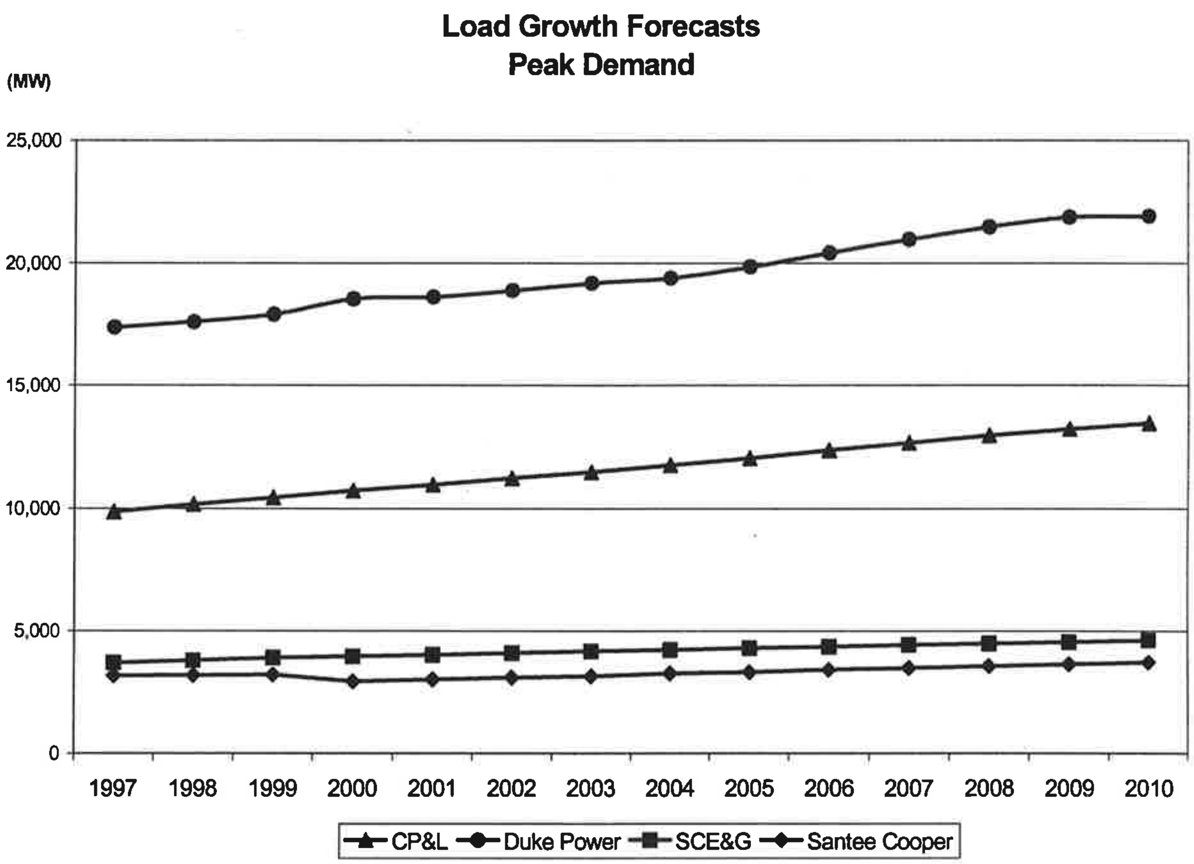
Santee Cooper's IRP does not include a description of the methodology employed in load forecasting. Duke Power explains that they apply econometric forecasting to project energy and demand for each of its customers classes, and then they use end-use forecasting to divide the econometric forecast by end-uses within the customer class. CP&L uses both econometric and end-use forecasting to develop load forecasts by end-uses. They claim that by doing so, "...results are compared to assess forecast consistency and reliability. This procedure acts as verification of the results of each model."[3] SCE&G provides extensive details about their econometric forecasting method, including the regression equations they use to forecast load data.

[3] See page 2-2 of the Energy and Peak Load Forecast Chapter, CP&L 1995 IRP Report.

For the economic forecast data and demographic data, utilities typically rely on consulting firms such as Decision Resources Incorporated (DRI) to provide the assumptions. SCE&G and CP&L both mention in their IRP reports that they obtained data from DRI. Duke indicated that they obtained historical and forecasted national and regional economic data from the company of Regional Financial Associates.

2. Peak Demand Forecasts

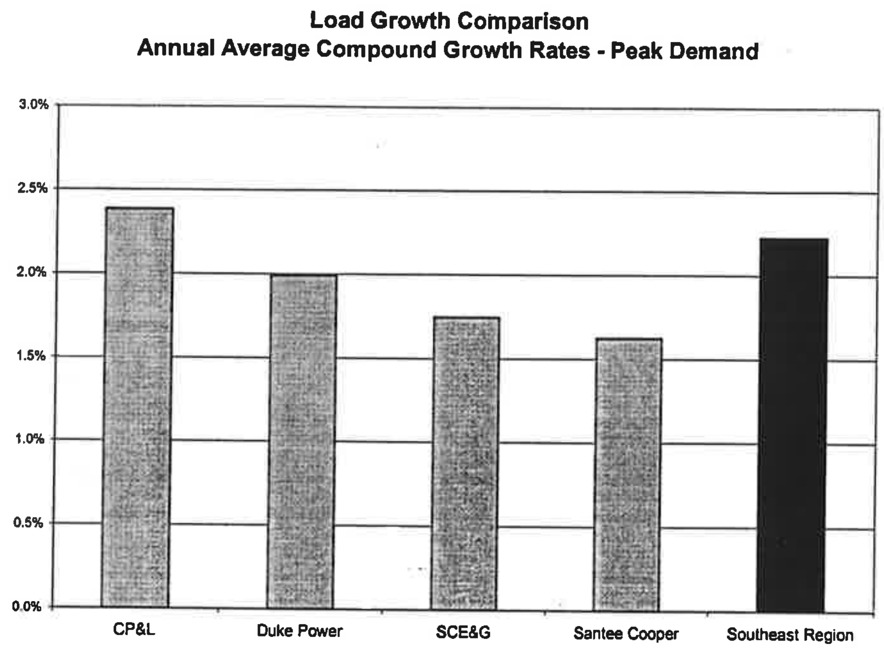
The following table shows the latest peak demand forecast provided by the utilities:



The utilities provided load forecasts in their original IRPs, which they updated in their annual STAPs. The graph above uses load forecast data taken from the last STAP available from each utility. The annual compound growth rates predicted by the utilities are 2.4% for CP&L, 2.0% for Duke, 1.7% for SCE&G and 1.6% for Santee Cooper. These rates appear to be reasonable when compared to the predicted regional growth rate for the Southeast of 2.2% per year.[4]

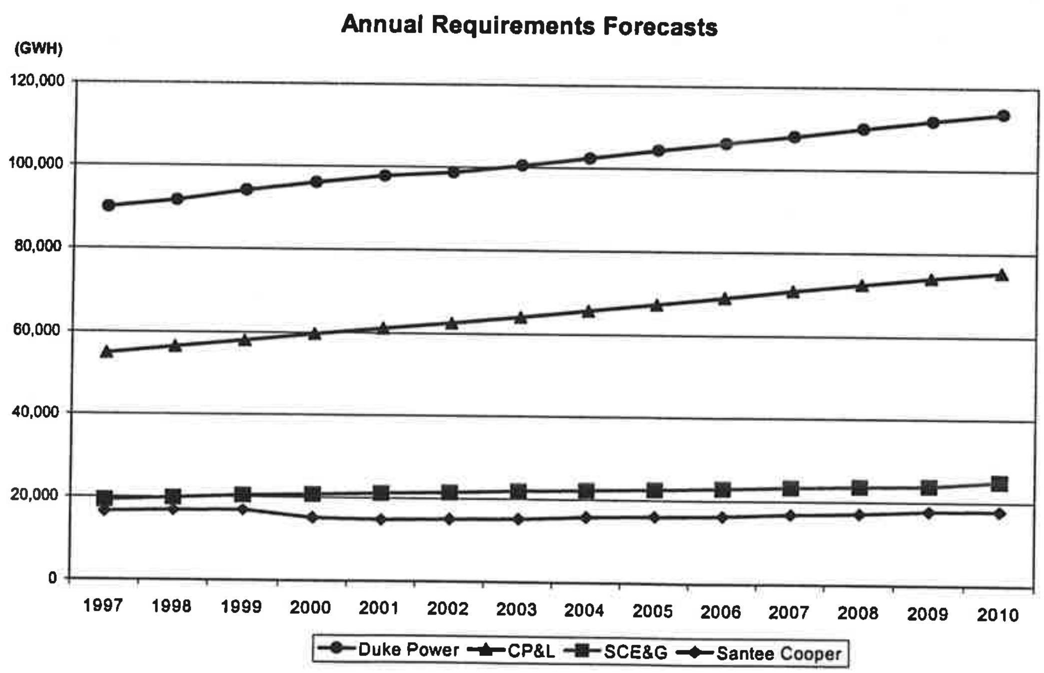
[4] Based on the June 1, 1997 SERC EIA-411

The following chart compares the peak demand growth rates of the South Carolina utilities to the regional growth rate:

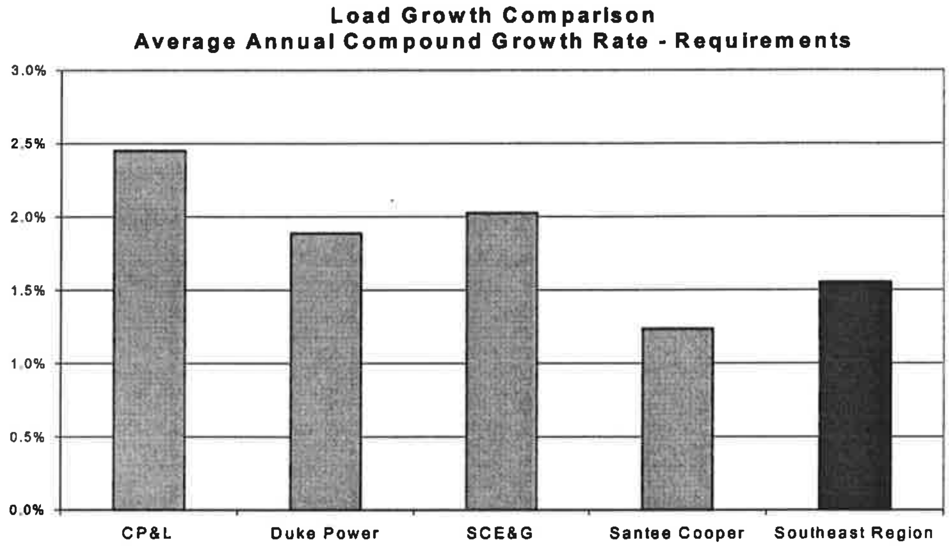


3. Annual Requirements Forecasts

The following chart shows the forecasted annual requirements of each utility:



The predicted annual compound growth rates for energy are 2.5% for CP&L, 1.9% for Duke, 2.0% for SCE&G and 1.2% for Santee Cooper. These are compared to the Southeastern regional energy growth rate of 1.6% on the following chart:[5]



4. Load Forecasting Accuracy

A comparison of the latest forecasted values to actual peak demand and annual energy required was conducted to evaluate the accuracy of the load forecasts developed by the utilities. Actual peak demands and annual energy requirements for 1994, 1995 and 1996 were compared to the last forecast published in either the 1995 IRP or a subsequent STAP. Actual data for this comparison was extracted from the data filed by the utilities via FERC Form 861. Certainly this is a limited comparison, having only two or three years of actual data, but potential problems may be revealed nonetheless.

It would be reasonable to expect that forecasted values would be higher than actual in some years and lower in other years. Unusual weather, such as hotter than usual or cooler than usual summer conditions is one factor that would result in such a comparison. The following evaluations are based on the table that appears on the next page.

[5] Based on the June 1, 1997 SERC EIA-411

Load Forecasting Accuracy

CP&L

	Peak Demand			Energy Required			
	Last Forecast (MW)	Actual (MW)	Percent Difference (%)	Last Forecast (GWh)	Actual (GWh)	Percent Difference (%)	Forecast Source
1995	9,690	9,500	2.00%	52,312	51,779	1.03%	1995 IRP
1996	9,816	8,952	9.65%	52,822	53,385	-1.06%	1997 STAP
Average			5.82%			-0.01%	

Duke Power

	Peak Demand			Energy Required			
	Last Forecast (MW)	Actual (MW)	Percent Difference (%)	Last Forecast (GWh)	Actual (GWh)	Percent Difference (%)	Forecast Source
1994	15,675	14,197	10.41%	83,309	80,119	3.98%	1995 IRP
1995	16,377	15,641	4.71%	85,842	81,376	5.49%	1996 STAP
1996	16,592	14,615	13.53%	87,482	81,593	7.22%	1997 STAP
Average			9.55%			5.56%	

Santee Cooper

	Peak Demand			Energy Required			
	Last Forecast (MW)	Actual (MW)	Percent Difference (%)	Last Forecast (GWh)	Actual (GWh)	Percent Difference (%)	Forecast Source
1994	2,954	2,639	11.94%	15,400	15,094	2.03%	1994 IRP
1995	3,056	3,056	0.00%	16,050	16,526	-2.88%	1994 IRP
1996	3,085	3,041	1.45%	16,100	18,026	-10.68%	1994 IRP
Average			4.46%			-3.85%	

SCE&G

	Peak Demand			Energy Required			
	Last Forecast (MW)	Actual (MW)	Percent Difference (%)	Last Forecast (GWh)	Actual (GWh)	Percent Difference (%)	Forecast Source
1995	3,533	3,683	-4.07%	18,439	18,657	-1.17%	1995 IRP
1996	3,529	3,698	-4.57%	18,870	19,753	-4.47%	1996 STAP
Average			-4.32%			-2.82%	

CP&L's forecasting results appear to be reasonable. Energy was forecast to approximately a 1% difference compared to actual in each year. Peak demand was fairly close in 1995, but in 1996 the peak demand was substantially over-forecasted. The actual peak dropped by almost 500 MW from the prior year. This situation was probably due to an anomaly in weather conditions, which would not have been predicted.

Duke Power has consistently over-forecasted both peak demand and annual energy requirements in the years 1994, 1995 and 1996. This problem is not likely to be weather-based, since it is consistent over the three years. There is a possibility that the problem is due to a reporting inconsistency, that is, that the actual values include wholesale loads that are not included in the forecasted values. In any case, an explanation is warranted. There may also be a problem with Duke's forecasting methodology.

Santee Cooper's forecasting was extremely accurate in forecasting the 1994 energy requirements, the 1995 peak demand and energy requirements and the 1996 peak demand. However, the 1994 peak demand was significantly over-forecasted and the 1996 annual energy requirements were dramatically under-forecasted.

SCE&G consistently under-forecasted both peak demand and annual energy requirements in the years 1995 and 1996. This appears to be a problem with SCE&G's forecasting assumptions and/or methodology.

Developing accurate load forecasts, or for that matter, almost any type of forecasts is a very difficult endeavor. It would not be entirely fair to criticize the utilities on the basis of examining only 3 years of data. It is normally expected that over time forecast error should be within a 0 – 5% range on an annual basis. However, it is perfectly understandable to see differences of more than 10% in any given year, due to conditions arising that are difficult to predict. It would be more revealing to analyze 10 years of forecast history to determine whether the utilities have done a credible job of load forecasting.

5. Load Forecasting Software Tools

The following table compares the software tools used by each company to develop their load forecasts, and provides an explanation of each of the tools that were used. Load forecasting is an important function of an electric utility, and utilities have recognized the importance of using accurate software tools to develop their load forecasts. Accurate load forecasting will be as critical, if not more so, in a competitive deregulated industry.

Software Tools Used to Develop Load Forecasts

Forecast Method	CP&L	Duke Power	Santee Cooper	SCE&G
Econometric	Yes, But Model Not Named	Yes, But Model Not Named	Unknown	Yes, But Model Not Named
End-Use			Unknown	Unknown
Residential	REEPS	REEPS		
Commercial	COMMEND	COMMEND		
Industrial	INFORM	INFORM		

<u>REEPS</u>
The Residential End-Use Planning System (REEPS) was developed by the Electric Power Research Institute (EPRI) and is used extensively by electric utilities across the U.S. for developing energy usage patterns for detailed residential end-uses. REEPS builds a residential forecast by segmenting the load into numerous residential appliance uses.

<u>COMMEND –</u>
The Commercial End Use Forecasting Model (COMMEND) was also developed by EPRI and is widely used by electric utilities across the U.S. for developing energy patterns for commercial end-uses. COMMEND builds a commercial forecast by segmenting the load by building type and end-uses within the various building types.

<u>INFORM</u>
The Industrial Forecasting Model (INFORM) was developed by EPRI as well. INFORM builds an industrial forecast by segmenting the load by Standard Industrial Classification Codes (SIC), and by end-uses within the SIC types.

B. Demand-Side Options Evaluation

1. General Considerations

Many utilities begin the process of the DSM evaluation by establishing objectives for the adoption of DSM programs at their utility. The objectives stated by each of the utilities in their 1995 IRP Report are as follows:

<u>SCE&G</u>

SCE&G stated that for the past decade much attention had been focused on conservation programs and in this IRP a greater emphasis is placed on those programs that would result in production resources being optimized, and that would apply downward pressure on rates. To meet those objectives, SCE&G planned to pay greater attention to DSM programs that had valley filling, load shifting and strategic load growth characteristics. At the same time, SCE&G pointed out that they were not planning to abandon conservation and peak clipping programs, because they have several programs targeted to those objectives.

<u>CP&L</u>

In their IRP report, CP&L states, "CP&L's current DSM efforts are focused on cost-effective peak load management, strategic conservation, and strategic sales programs which will help reduce peak load, improve the utilization of existing facilities, and defer the need for future rate increases."[6]

<u>Duke Power</u>

Duke explains that in this IRP, they focused on an increasingly competitive marketplace. Duke stated that they tried to design a "...balanced portfolio that encompasses energy efficiency, strategic sales, interruptible, and load-shift options."[7]

<u>Santee Cooper</u>

Santee Cooper was somewhat vague about having DSM objectives, although they did say that conservation, peak clipping, and load shifting would be acceptable load shape objectives.

The utilities are collectively saying that the industry is becoming increasingly more competitive and they all want to supply energy at rates that are as low as possible. Almost in unison they are saying that to meet this objective they will have to avoid implementing DSM programs that place upward pressure on rates.

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[6] See page v of the Executive Summary, CP&L's 1995 IRP report
[7] See page 46, Chapter 4, Demand-Side Resources, in Duke Power's 1995 IRP Report

2. DSM Evaluation Steps

Utilities typically begin the DSM evaluation process by compiling a comprehensive list of potential DSM programs. As an example, Santee Cooper stated that they initially assembled a list of 227 potential options. Analyzing all of the options in detail, would take an enormous amount of time, and therefore, DSM programs are removed from further consideration based on a series of screening steps.

First, a set of qualitative screens are applied. For example, Santee Cooper discussed how they performed a series of 3 qualitative screens concerning the following issues:

1. Did the DSM programs meet the required load shape objectives? Santee Cooper preferred DSM programs that had conservation, peak clipping, and load shifting characteristics.
2. How willing would Santee Cooper's customers be to adopt the DSM programs? Programs that were deemed to have adverse impacts on Santee Cooper's customers were dropped from further consideration.
3. Would it be technically feasible to implement the DSM program in the marketplace?

Based on these qualitative screens, Santee Cooper was able to eliminate a significant number of DSM options.

DSM programs were then evaluated using an economic screening analysis that considered the cost effectiveness of the DSM program. A set of cost effectiveness ratios, called the Standard California Cost Effectiveness Tests were utilized. These tests are used extensively throughout the U.S. to analyze DSM programs. Tests include the Total Resource Cost (TRC) Test, The Utility Cost Test, the Participants Test and the Rate Impact Measure (RIM) test.[8]

The basic idea behind the economic screening is to find all DSM programs that when added to an Initial Base Supply Plan result in a reduction in costs.[9] So, in order to be considered cost effective, the resource plan with the DSM option has to beat out the Base Supply Plan alone.

These cost effectiveness tests require an extensive amount of data to be compiled.

Data requirements include:

[8] See Appendix A for the calculations of the DSM Cost Effectiveness Tests
[9] Please refer to Section III.D.1 for more information on developing the Initial Supply Plan, and resource optimization techniques.

- DSM program load shape impacts (preferably hourly load shape data)
- Utility costs including administrative costs, marketing expenses, education expenses, rebates, customer loans, etc.
- Customer participation expenses
- Marketing evaluation information which answers questions about who the target market is, how will the program be marketed, and what kind of customer acceptance can be expected

As more and more utilities have been actively pursuing DSM projects, this information has become more readily available. In an effort to further the development of good DSM databases covering the Southeast region, both SCE&G and CP&L state that they are participating in a collaborative end-use load research project sponsored by the EPRI's Center for Electric End-Use Data (CEED). The purpose of the project according to CP&L is to "...facilitate the transfer of end-use load research data to utilities in the Southeast."[10]

A DSM cost effectiveness evaluation involves the gathering of all of the costs and benefits required by the particular DSM test specified above. Certain costs can be derived based on a marketing analysis of the DSM program, while other costs require a production cost simulation to develop. Utility Program Costs, Incentive Payments, Participants Bill Reduction, Participants Costs and Lost Revenues are all costs that can be determined from a marketing analysis of the program.

Avoided Capacity Costs and Avoided Energy Costs are those costs that the utility would incur if they did not implement the DSM program. There are a number of ways to produce these cost estimates, all of which involve performing a production cost simulation of the system in some way.[11] CP&L and SCE&G first develops estimates of avoided energy ($/MWh) and avoided capacity rates ($/kw). To calculate the total dollar impacts, they then multiply the avoided energy and capacity rates by the energy and peak demand impacts of each DSM program. CP&L and SCE&G derived avoided energy costs by running a production cost simulation twice, once to make a Base Case Run and the second time to decrement the load by some amount of capacity.[12] The difference in variable production costs between the two runs is taken as the avoided energy cost.

SCE&G calculates avoided capacity costs by developing two expansion plans, one without and the other with some reduction in capacity to represent a generic amount of DSM. The difference in the capacity related costs, including capital costs and fixed O&M expense, represents the company's avoided capacity costs.

CP&L calculates avoided capacity costs using what is known as the "Peaker Method".[13] In this method avoided capacity costs are assumed to be based on the least

[10] See page 3-21 of the Demand-Side Management Chapter, CP&L 1995 IRP Report.
[11] For more information regarding production cost software, see section III.D.4 below.
[12] SCE&G makes 5 runs in order to calculate seasonal and time-differentiated avoided energy costs
[13] CP&L credits NERA as having originated this method.

cost generation technology which is assumed to be the type of capacity that would be avoided by DSM.

While the methods to compute avoided capacity and energy values used by both CP&L and SCE&G have been widely used and accepted in regulatory filings by other utilities across the country, the methods have some potential problems:

1. In the case of SCE&G, separate model runs are made using different data assumptions to develop the avoided capacity and energy costs. This can lead to inconsistencies in the results.
2. In the case of CP&L they assume that DSM would avoid only Combustion Turbine (CT) capacity while in reality, DSM could avoid any type of capacity including base load. This often results in understating the avoided capacity benefits of DSM.
3. A dubious modeling assumption is made about the characteristics of the DSM load shape in the runs that include DSM. Based on an assumed load shape for DSM, avoided energy costs are derived once and then used for all DSM programs. These avoided costs are used in the calculation of every DSM program the utility considers, regardless of the true hourly impacts of each DSM program.

Perhaps the utilities were on the lookout for these pitfalls, but these issues were not discussed in their reports.

While Santee Cooper did not describe all of the steps they performed to develop avoided capacity and energy costs, it appears that they calculated avoided costs in an integrated fashion. That is, avoided capacity and energy costs were derived by performing two production cost simulations, one with and one without the specific DSM program being evaluated. The difference in capacity related costs between the two runs was the avoided capacity cost, and the difference in energy related costs between the two runs was the avoided energy cost.

The benefit of this approach is that the exact hourly characteristics of the DSM programs are modeled and capacity and energy costs are derived on the basis of the exact amount and type of capacity and energy avoided by the specific DSM program. This results in a more accurate evaluation of each DSM program. Duke Power did not provide any information regarding the methods or software tools they used to calculate avoided costs.

In addition to crediting DSM programs for avoided generation capacity costs, both CP&L and SCE&G stated that they credited DSM programs for avoided transmission and distribution investments, which is appropriate. In fact, CP&L stated their avoided transmission cost was $260/kw and their avoided distribution cost was $606/kw.[14] Neither Santee Cooper nor Duke Power mentioned whether they included avoided transmission or distribution costs in their evaluation of DSM programs.

[14] See page D-2 of Appendix D, CP&L 1995 IRP Report

Each utility used their own judgement to determine what cost effectiveness criteria to use for eliminating DSM programs from further examination. Here is a summary of the strategies used by each of the utilities:

Santee Cooper

Santee Cooper eliminated all programs that scored less than 1.0 on the TRC, Utility Cost, and RIM tests. Once programs had been eliminated, Santee Cooper then created portfolios of DSM programs that they passed on to the Integration Process for further analysis. One portfolio contained only programs that had positive TRC test net benefits, another had only positive Utility Cost Test net benefits, a third had only positive RIM net benefits, and the final one had both positive RIM and positive TRC net benefits.

SCE&G

SCE&G's criterion was to select DSM programs that had positive TRC and RIM test net benefits. However, in certain cases such as with the Good Cents/Conservation Program, SCE&G decided to implement the program despite having negative RIM net benefits. SCE&G stated, "The Company considers it a reasonable balance between the ratepayer's needs and the societal objective of promoting conservation." In other cases, SCE&G decided to implement programs that had positive RIM and Utility Cost net benefits such as with the High Efficiency Heat Pump Program. (This program had negative benefits from the Participants Test perspective). This implies that costs to the utility and rate-payers would go down, but costs to the participant would be greater than the benefits derived from the program.

Duke Power

In evaluating the cost effectiveness benefits, Duke took the evaluation process one step further by performing a Cumulative Analysis Assessment. This is a good approach, because it recognizes that once a certain amount of DSM has been added to the system the marginal benefit of the next increment of DSM added will not be as great as the previous amount added. Essentially, avoided energy costs are recomputed after each amount of DSM has been added, and are then used to assess the value of the next amount of DSM added to the system.

Duke accepted programs as long as RIM test results were greater than one. If not, Duke looked at the TRC and Utility Cost Tests, and if they were both greater than one, then Duke accepted the DSM programs. Duke mentioned that if programs did not meet any of those requirements, they would consider redesigning or dropping the programs.

CP&L

CP&L decided to accept only those DSM programs that showed positive RIM benefits. According to CP&L, "This methodology (RIM) results in decisions, which are in the best interest of the utility's entire body of customers. Use of the RIM test to evaluate DSM options is also consistent with operating in a more competitive environment because it focuses on minimizing rates."

Decisions to adopt DSM programs can be made strictly on the basis of the cost effectiveness evaluation results, or DSM programs can undergo further analysis as part of the Supply-Side and Demand-Side Integration Process. Duke, CP&L, and SCE&G adopted all of the programs that passed the cost effectiveness evaluation without further evaluation. Santee Cooper on the other hand, passed DSM options on for further evaluation in the Integration Step.

3. Options Considered

The previous section focused on the methods that the utilities used to evaluate DSM options in their 1995 IRP Report. During the intervening years, the utilities continued to analyze their DSM plans and made decisions that resulted in the modification or the complete elimination of some of the programs.

The following tables list each of the Demand-Side Options that were considered by one or more of the utilities in the IRP development process, organized first by customer group (residential, commercial, industrial) and then by program type (Conservation, Direct Load Control, Load Building or Rate). The tables also show which programs were selected by the utilities as a part of its IRP and finally, which programs were actually implemented by the utilities. Those programs that were considered by all four utilities have been shaded. Programs that survived from the "Considered" to the "Selected" category were chosen because they passed all of the screening steps, and in the case of Santee Cooper, they were found to be cost effective in the integration phase, as well.[15]

For purposes of this report, DSM programs have been logically grouped together. Conservation programs are generally programs that cause continuous reductions in the use of electricity, such as additional wall insulation in homes. These programs normally have a significant impact upon the annual requirements of the utility and a less significant impact on the annual peak demand. Load control programs generally cause significant reductions in the peak demand by allowing the utility to shut-off high–use electrical equipment, such as air conditioners, at the time of annual peak. At the same time, load control programs generally have a less significant impact on energy requirements. Load Building programs are programs that actually encourage or increase the use of electricity in off-peak periods, while Rates are DSM programs that encourage customers to reduce electric usage in on-peak hours by sending appropriate price signals.

Of the 67 programs that were considered by at least one utility, only four were considered by all four utilities. There appears to be little, if any, sharing of information among the utilities concerning the programs that are likely to be successful in South Carolina. This is especially surprising in light of the fact that both CP&L and SCE&G are participating in EPRI's collaborative CEED project. The entire premise of the project was to share information with other utilities in the Southeast.

Duke is the only utility that considered commercial and industrial Load Building programs as viable DSM programs. These programs might be better classified as marketing programs rather than DSM programs. SCE&G is the only company that did not consider residential Load Control programs.

The reduction in the number of programs that were actually implemented compared to those that were selected in the IRP reflects the fact that the utilities have recently

[15] In an attempt to make fair comparisons of the DSM programs from one utility to the next, certain aggregations of program types had to be made.

backed away from some of the DSM programs selected in the 1995 IRPs. Little economic justification for this was supplied in the STAPs. Instead vague references were made to the declining cost of supply-side resources, increased competition among utilities, and the need to develop DSM programs that have negligible rate impacts. In fact, Santee Cooper has failed to implement any of the programs selected in its IRP. The programs shown as implemented by Santee Cooper were in place prior to the IRP development. Many of the programs that Santee Cooper and the other utilities have chosen not to implement showed positive RIM test benefits, which the utilities allege to be one of the most important criteria for implementing DSM programs in a competitive industry.

DSM Programs

C-Considered in the IRP, S - Selected in the IRP, I – Implemented

	CP&L			Duke			Santee Cooper			SCE&G		
Residential	C	S	I	C	S	I	C	S	I	C	S	I
Conservation												
Compact Fluorescent Lighting										◆		
Duct Testing & Repair				◆			◆	◆				
Existing Home Thermal Efficiency	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆
Existing Home Thermal Efficiency Loan Program	◆	◆	◆									
Ground Source Heat Pumps							◆					
Heat Pump Pool Heaters										◆		
Heat Pump Water Heater	◆	◆										
High-Efficiency Air Conditioner				◆	◆					◆		
High-Efficiency Heat Pump	◆	◆	◆	◆	◆		◆			◆	◆	◆
High-Efficiency Water Heater	◆	◆								◆	◆	◆
Home Comfort Analysis	◆	◆	◆							◆	◆	◆
HVAC Tune-Up				◆	◆		◆					
Manufactured Home Common Sense Environmental	◆	◆										
New Home Low-E Windows				◆	◆							
New Home Programmable Thermostat				◆	◆							
New Home Thermal Efficiency	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆
New Manufactured Home Thermal Efficiency	◆	◆	◆	◆	◆		◆					
Off-Peak Water Heating										◆		
Thermal Storage										◆		
Water Conservation									◆			
Load Control												
Air Conditioning Load Control	◆	◆	◆	◆	◆	◆	◆					
Swimming Pool Pump Load Control							◆					
Water Heater Load Control	◆	◆	◆	◆	◆	◆	◆		◆			
Rates												
Low Use Rate Discount										◆	◆	◆
Time-of-Use Rate	◆	◆	◆							◆	◆	◆

DSM Programs

C-Considered in the IRP, S - Selected in the IRP, I - Implemented

	CP&L			Duke			Santee Cooper			SCE&G		
Commercial	C	S	I	C	S	I	C	S	I	C	S	I
Conservation												
Adjustable Speed Drives										◆		
Energy Audit	◆	◆	◆									
Energy Efficient Heat Pump	◆	◆		◆	◆	◆				◆	◆	◆
Energy-Efficient Design	◆	◆	◆				◆	◆	◆			
Fluorescent Ballasts										◆		
Gas Air Conditioning										◆		
Heat Pump Pool Heaters										◆	◆	
Heat Pump Water Heaters										◆	◆	
High Efficiency Chillers				◆	◆					◆	◆	◆
High Efficiency Compressed Air Systems				◆	◆	◆						
High Efficiency Indoor Lighting				◆	◆		◆	◆		◆		
High Efficiency Large Unitary Equipment				◆	◆							
High Efficiency Motor Replacement				◆	◆	◆				◆		
High Efficiency Motor Systems				◆	◆	◆	◆	◆				
High-Efficiency Air Conditioner				◆	◆		◆	◆		◆	◆	◆
Thermal Energy Storage	◆	◆	◆	◆	◆		◆		◆	◆	◆	◆
Thermal Energy Storage - Schools	◆	◆										
Load Control												
Commercial Load Control	◆	◆		◆	◆	◆				◆	◆	◆
Small Load Curtailment	◆	◆	◆									
Standby Generator Control				◆	◆	◆	◆			◆	◆	◆
Load Building												
Electrotechnology Strategy				◆	◆	◆						
High Efficiency Food Service Appliances				◆	◆	◆						
Outdoor Lighting				◆	◆							
Rates												
Real Time Pricing										◆	◆	
Time-of-Use Rate	◆	◆	◆							◆	◆	◆

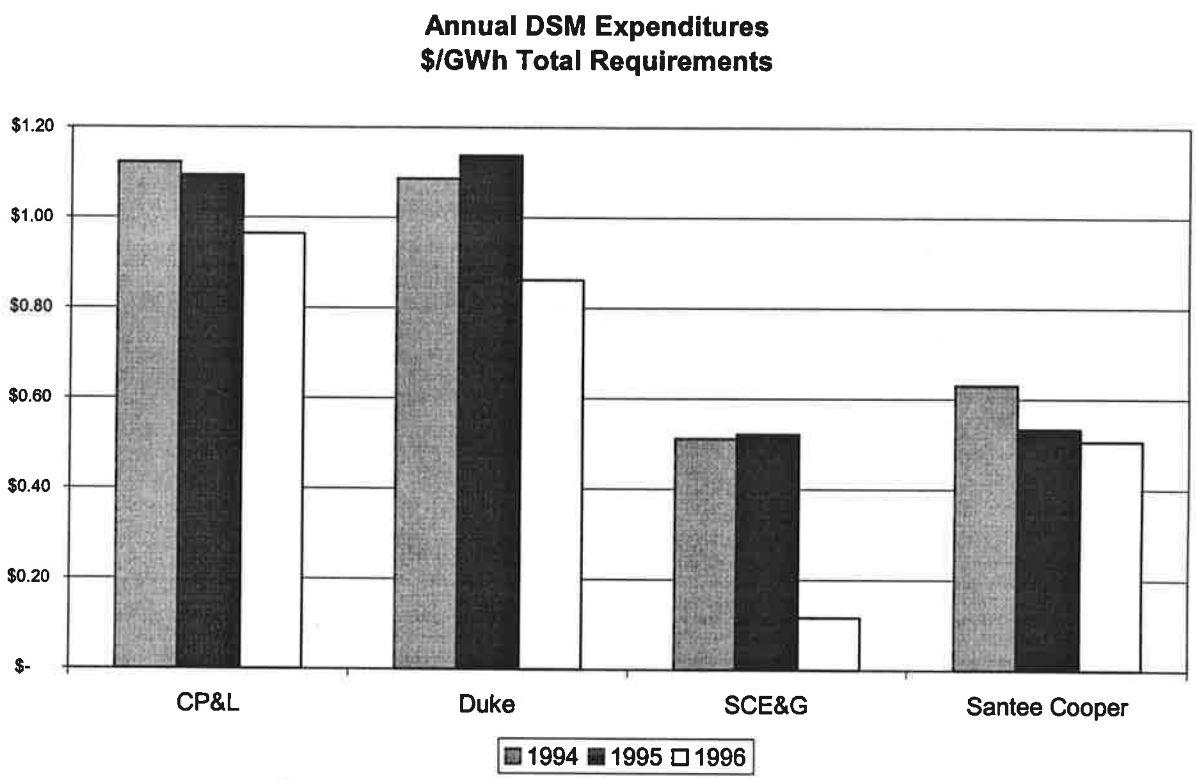
DSM Programs

C-Considered in the IRP, S - Selected in the IRP, I - Implemented

	CP&L			Duke			Santee Cooper			SCE&G		
Industrial	C	S	I	C	S	I	C	S	I	C	S	I
Conservation												
Adjustable Speed Drives										◆		
Energy Audit/Energy-Efficient Plants	◆	◆	◆									
Fluorescent Ballasts										◆		
Gas Air Conditioning										◆		
High Efficiency Chillers				◆	◆					◆		
High Efficiency Compressed Air Systems				◆	◆	◆						
High Efficiency Indoor Lighting				◆	◆		◆	◆		◆		
High Efficiency Large Unitary Equipment				◆	◆							
High Efficiency Motor Replacement				◆	◆	◆				◆		
High Efficiency Motor Systems				◆	◆	◆	◆	◆				
Thermal Energy Storage				◆	◆		◆			◆		
Load Control												
Large Load Curtailment	◆	◆	◆	◆	◆	◆				◆	◆	◆
Standby Generator Control				◆	◆	◆	◆			◆	◆	◆
Load Building												
Electrotechnology Strategy				◆	◆	◆						
Outdoor Lighting				◆	◆							
Rates												
Real Time Pricing										◆	◆	
Time-of-Use Rate	◆	◆	◆							◆	◆	◆
Total Number of Programs	23	23	17	36	35	18	20	9	6	38	21	17

4. DSM Spending

The following chart compares the spending of the four utilities on DSM programs. Total actual annual DSM expenditures have been divided by total annual requirements (in GWh) to provide scaled values in dollars per GWh. Since not all of the utilities provided this information in their IRP Reports, the expenditure data was taken from the companies' filings in EIA Form 861.

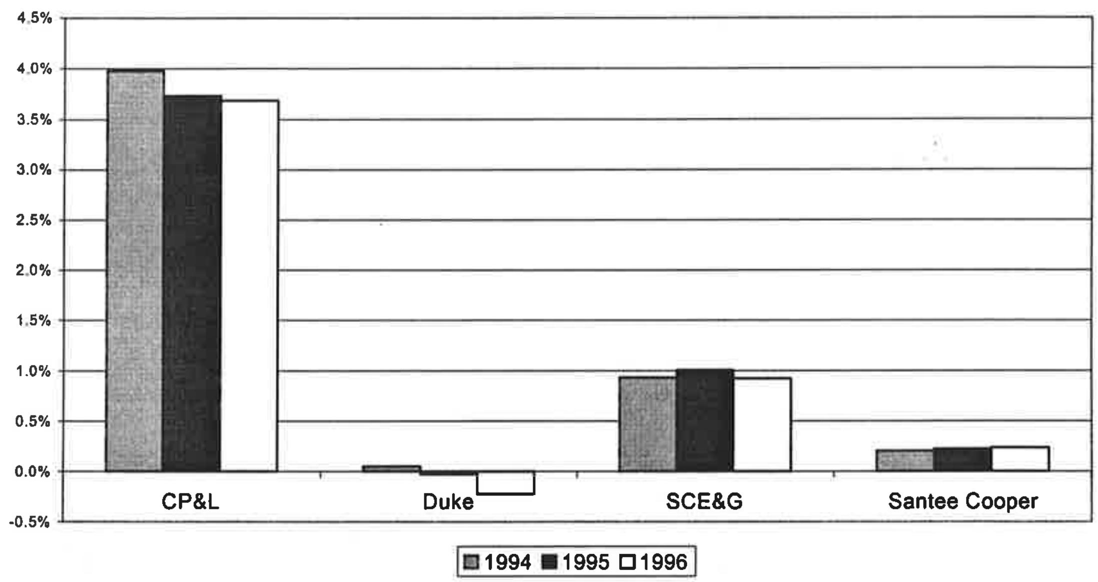


The decline in DSM spending is consistent from one utility to the next and is explained by each utility as being an effort to eliminate spending on DSM that ultimately results in customer rates increasing. It is clear from this chart that SCE&G and Santee Cooper never made the level of financial commitment to cost-effective DSM that CP&L and Duke made. It is also clear that while CP&L, Duke and Santee Cooper dropped their DSM spending from the previous years by a small amount, the decline in DSM spending at SCE&G was precipitous.

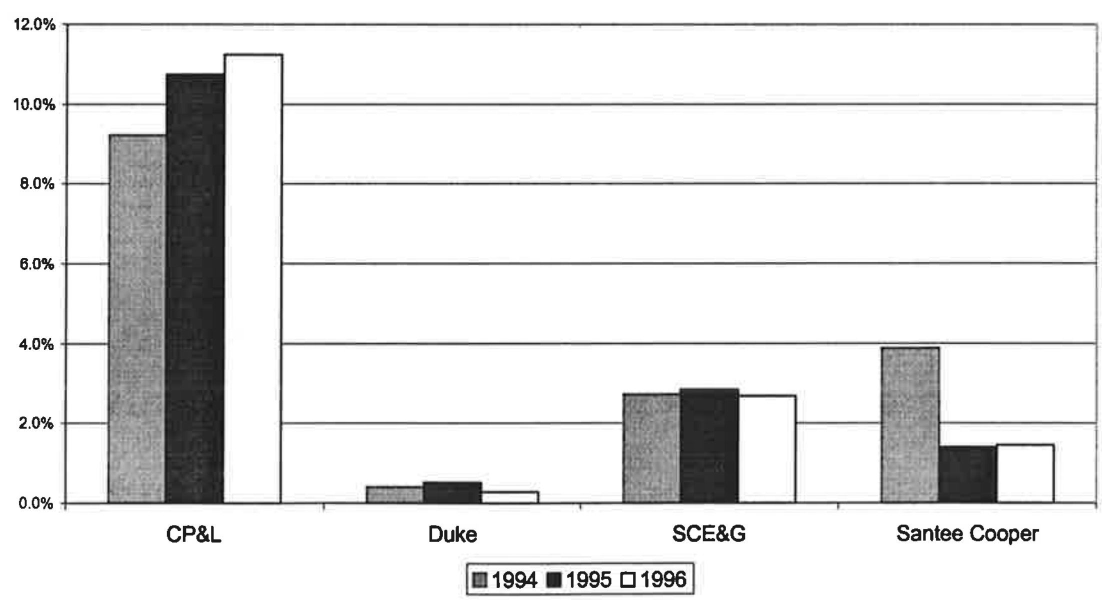
5. DSM Impacts

The following charts show the actual achieved DSM impacts for 1994-1996 as reported by the companies in EIA Form 861.

Actual DSM Energy Savings as a Percent of Total Requirements



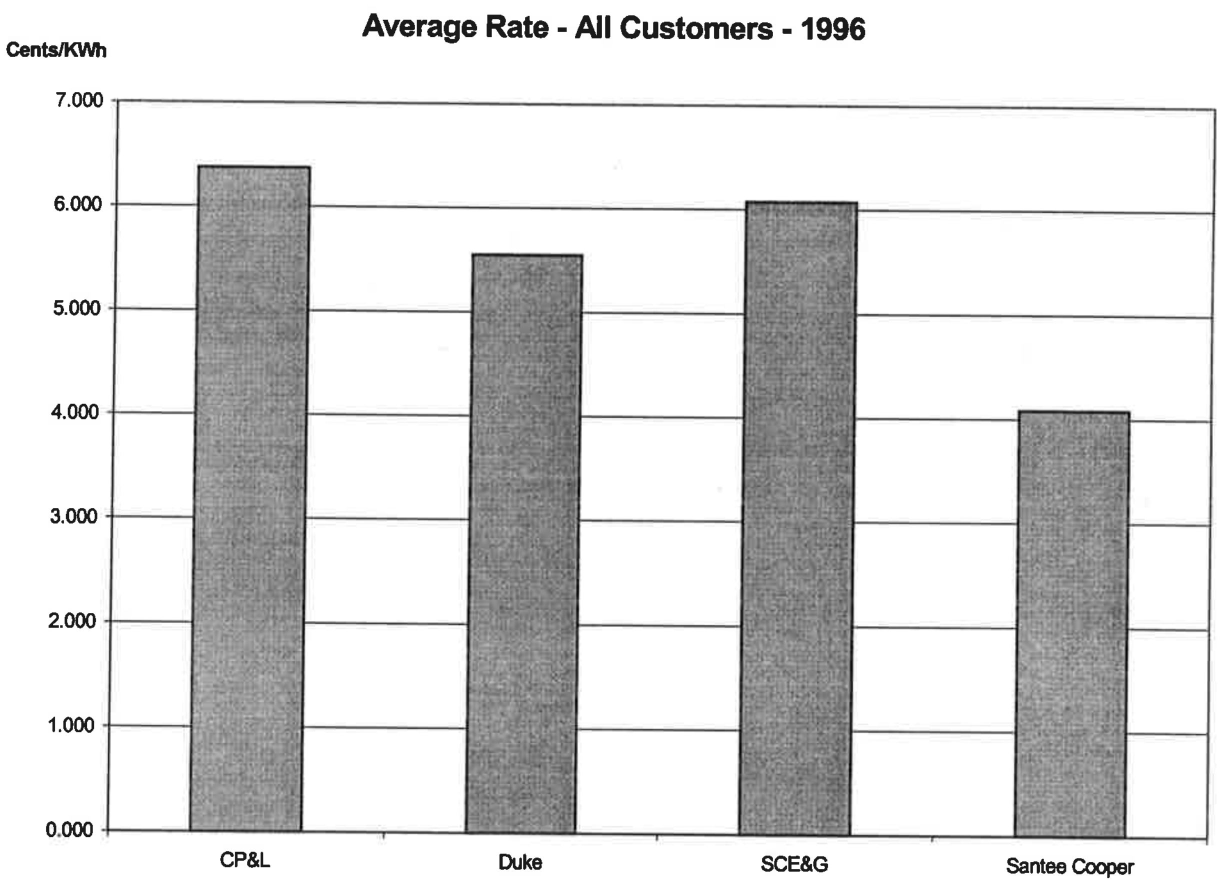
Actual DSM Peak Demand Savings as a Percent of Peak Demand



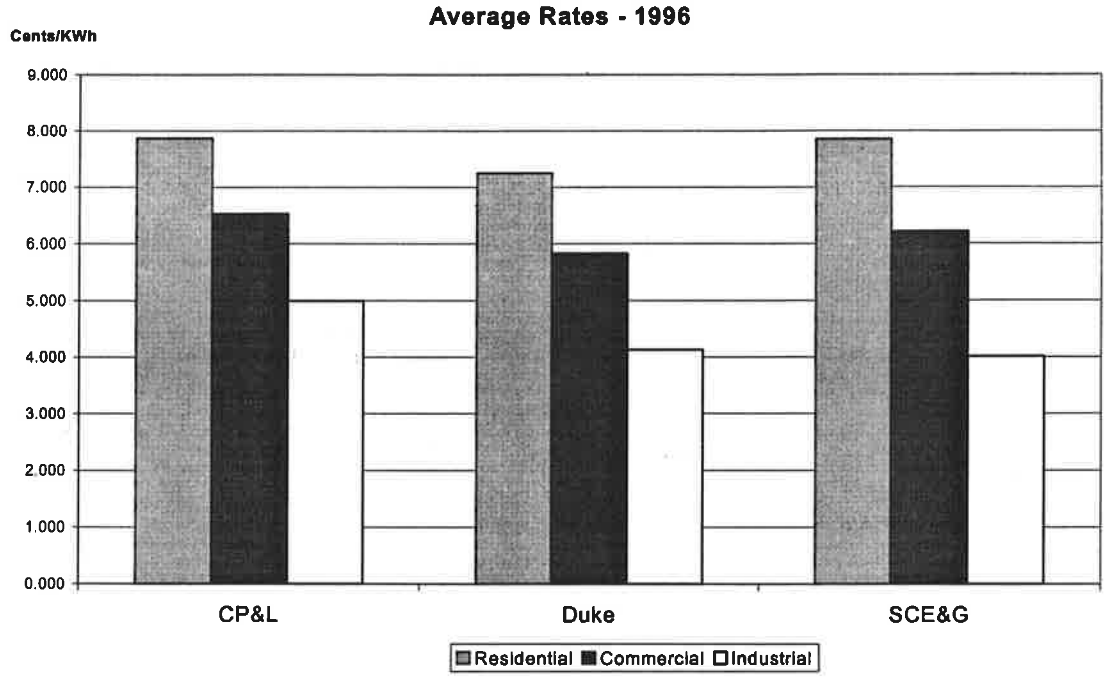
The extremely low (and even negative) savings shown for Duke are the result of Duke's load building programs that negate the savings from other programs. It is clear from these charts that CP&L is achieving DSM results that far surpass any of the other utilities.

6. Rate Impacts

The South Carolina utilities generally concur that many DSM programs (especially conservation programs containing customer rebates) will have a significant upward impact on rates and thus should be avoided as full competition with other utilities approaches. The following charts compare the average rates for all customers in 1996 and the average rates by customer class for the investor-owned utilities. This data was taken from the FERC Form 1 for the investor-owned utilities and from the EIA Form 861 for Santee Cooper.[16]



[16] Average rates by rate class information was not available for Santee Cooper



Even though CP&L expended substantially more dollars on DSM programs in 1994-1996 than SCE&G and Santee Cooper, the rates for CP&L's customers are only slightly higher than those for the other three utilities. In fact, SCE&G's residential rate in 1996 was essentially equal to CP&L's residential rate in that year. This information calls into question the notion that DSM can cause substantial rate increases.

7. National DSM Comparison

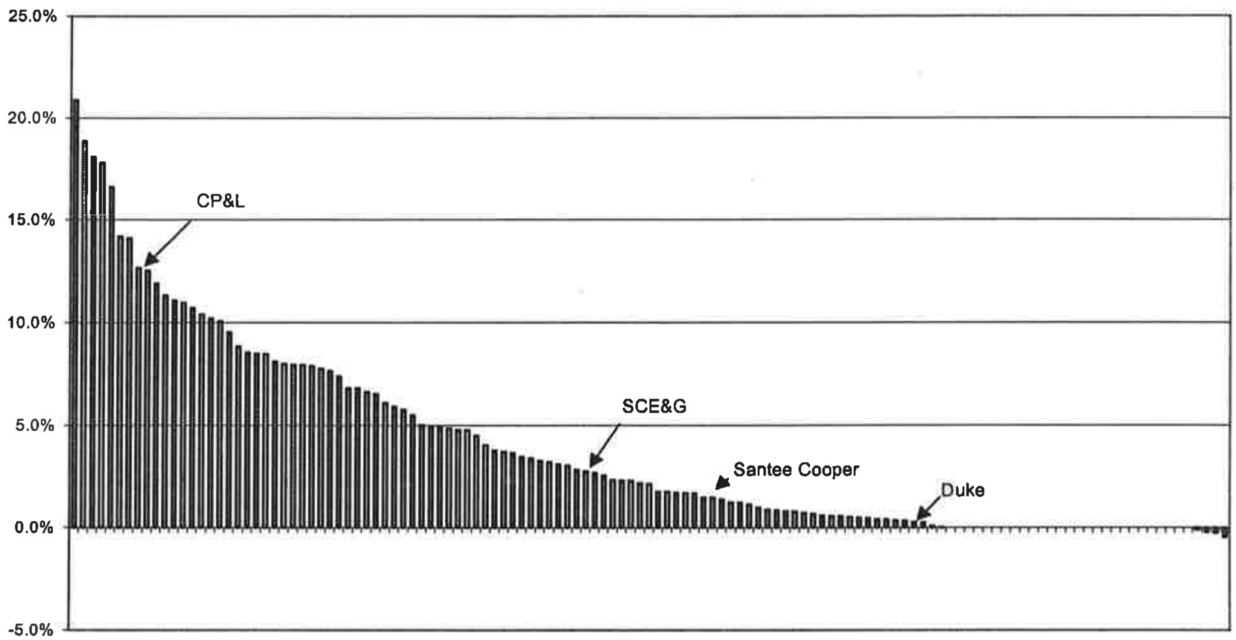
All electric utilities are required to file achieved DSM results via Form 861 of the Energy Information Administration. (or EIA). This publicly available data provides the information to compare the achievements of the South Carolina utilities to other utilities in the country. The tables below show the relative 1996 rankings of the South Carolina utilities according to two measures – DSM energy savings as a percentage of total requirements and DSM peak demand reductions as a percentage of total peak demand. All electric utilities having a 1996 peak of 1,000 MW or higher are considered.

	Energy Savings		Peak Demand Savings	
	Ranking	Savings	Ranking	Savings
Highest Achievement	1	7.3%	1	20.9%
CP&L	20	3.8%	8	12.7%
SCE&G	54	0.9%	57	2.7%
Santee Cooper	72	0.2%	70	1.5%
Duke Power	119	-0.2%	93	0.3%
Lowest Achievement	127	-3.3%	127	0.0%
Average Achievement		1.3%		4.0%

The 1996 achievements for all 127 utilities considered is shown in the charts on the following pages.

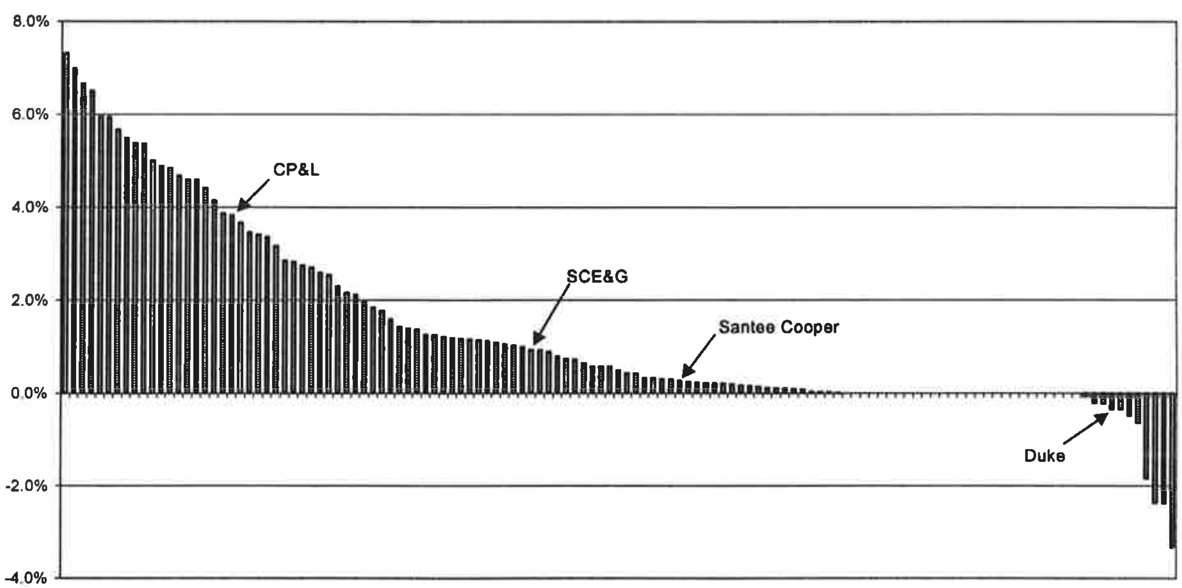
CP&L has achieved an impressive level of savings from their DSM programs. The other South Carolina utilities have failed to achieve even the average national savings.

**1996 DSM Peak Demand Savings
as a Percentage of Peak Demand**



U.S. Utilities with Peak Demand of 1,000 MW or more
Source - 1996 EIA Form 861

**1996 DSM Energy Savings
as a Percentage of Total Requirements**



U.S. Utilities with Peak Demand of 1,000 MW or more
Source - 1996 EIA Form 861

8. DSM Evaluation Software Tools

The DSM Option Evaluation Process involves performing a number of tasks as discussed in Section II.B above. The information requirements include:

- DSM program load shape impacts (preferably hourly load shape data)
- Utility costs including administrative costs, marketing expenses, education expenses, rebates, customer loans, etc.
- Customer participation expenses
- Marketing evaluation information which answers questions about who the target market is, how will the program be marketed, and what kind of customer acceptance can be expected

Software tools are employed to assist in developing this data and to help perform the DSM evaluation.

The following table contains the tasks where software tools were used by the Utilities in South Carolina.

Software Tools Used to Develop DSM Data and to Evaluate DSM Options

TASK	SCE&G	Santee Cooper	CP&L	Duke Power
DSM Program Development	ESPRE/ MICRO-AXCESS/ COMTECH	Worked With Consulting Firm, Metzler & Assoc. Conducted a Literature Search	Worked With Consulting Firm, Xenergy to Develop DSM Programs	Not Stated
DSM Avoided Capacity Costs	EGEAS	DSVIEW	Peaker Method	Not Stated
DSM Avoided Energy Costs	ENPRO	DSVIEW	Worked with Xenergy to Develop	Not Stated
DSM Program Cost Effectiveness	DSManager	DSVIEW	Worked with Xenergy to Develop	Not Stated

ESPRE – Developed by EPRI for creating residential load shapes associated with DSM programs

MICRO-AXCESS – Originally developed by EEI, later taken over by EPRI, it is used to develop energy load shapes associated with DSM programs in Commercial and Industrial facilities.

COMTECH – Developed by EPRI, used as a screening tool to evaluate different commercial building technologies

EGEAS – Originally developed by EPRI, now commercially available from Stone & Webster. This model can be used to perform production cost simulation, DSM analyses, resource optimization, environmental analysis, and financial modeling.

ENPRO – Originally developed by ENTEC, now owned and licensed by Henwood Energy Services, Inc. ENPRO was developed as a production cost analysis tool. Henwood Energy Associates acquired the model within the last few years.

DSManager – Originally developed by EPRI, now commercially available from EPS Solutions, Inc. This tool is used primarily as a DSM cost/benefit assessment tool.

DSVIEW, GAF and PROVIEW – Developed by NewEnergy Associates as Integrated Modules within the PROSCREEN II software system. (NewEnergy Associates was formerly Energy Management Associates). This model can be used to perform production cost simulation, DSM analyses, resource optimization, environmental analysis, and financial modeling.

C. Supply-Side Options

1. General Considerations

Similar to the DSM evaluation, utilities generally begin the process of analyzing Supply-Side resources by establishing objectives and assembling a complete list of all potential options available to them. In determining their objectives, utilities consider such things as whether they are open to purchase capacity to meet their needs and whether they are willing to consider non-conventional technologies as part of their evaluation. Also, like the DSM evaluation, an effort is made to initially reduce the total number of supply-side options to a more manageable amount.

Comments made by the utilities regarding their willingness to include certain types of capacity in their evaluation include:

<u>SCE&G</u>

SCE&G performed a technology review in which they evaluated both conventional and non-conventional technologies. "As a result of this review, SCE&G has concluded that there does not currently exist a non-conventional supply technology which exhibits both the maturity and the competitive costs required to be selected as a viable supply side alternative."[17] SCE&G goes on to say that fuel cells and solar photovoltaic cells look promising for reconsideration in the future, although it is not clear from their STAPs that they ever did re-evaluate these technologies.

<u>Duke Power</u>

Duke categorized technologies as Conventional, Demonstrated, or Emerging. According to Duke, demonstrated technologies have been used but have not achieved widespread acceptance or use in the industry. In 1995 Duke also initiated a Request For Proposal (RFP) to consider proposals for capacity that could be supplied beginning in 1998.

<u>CP&L</u>

Once CP&L assembled their list, they screened technologies based on the following criteria, in this order:

1. Significantly available in the CP&L service territory
2. At least currently available in the demonstration stage
3. Environmentally compatible with current regulations and public perceptions
4. Economically competitive with other technologies based on a screening curve analysis

[17] See page 4.15, Chapter 4 Supply-Side Planning, SCE&G 1995 IRP Report

Regarding purchase power capacity, CP&L evaluated 10 proposals from 8 different sources, and found them less cost competitive than CP&L's own planned capacity additions.

Santee Cooper

Santee Cooper categorized technologies as conventional, emerging, and purchased power. Regarding emerging technologies, Santee Cooper states, "An overriding criterion utilized in the screening of the various alternative technologies is Santee Cooper's approach to pursue only proven technologies. This approach minimizes the risks to the ratepayers resulting from the failure of the technology to materialize as rapidly or as effectively as originally anticipated. "[18] Despite this, Santee Cooper included a few options that they considered to only be in the demonstration phase for further analysis.

2. Options Considered

The following table shows the Supply-Side options that were considered by each of the utilities, included in the Integration Process, and selected in the final IRP. Of the 41 options that were considered by some utility, 13 were considered by all four utilities (these are shaded in the table).

Only Duke Power considered re-powering existing generating plants to current technology.

Three of the four utilities explicitly considered purchasing power from other utilities or non-utilities in the IRP. Duke was the only company that did not consider combined cycle (CC) generating units in its Integration Step, which is extremely curious. In their 1995 IRP, Duke simply stated, "To narrow the supply-side selection still further, Duke conducts a more detailed screening to analyze how future technologies interact with Duke's current generating system."[19] No other information was given as to how or why they screened out certain options such as CC units. Similar statements were made by the other utilities, but because Duke did not consider CC units in the Integration Phase, it calls attention to either Duke's screening methodology or to their data assumptions for modeling future units.[20]

In Duke's 1997 STAP, they finally did acknowledge the benefits of gas technologies by saying "Natural gas prices are expected to continue their decline, making gas-fired generation resources increasingly more attractive for meeting future resource needs."[21] In their 1997 STAP, Duke Power eliminated all base load coal units in favor of peaking

[18] See page 111, Chapter V Supply-Side Resource Options, Santee Cooper 1995 IRP Report
[19] See page 70, Chapter 5 Resource Integration, Duke Power Company 1995 IRP Report
[20] Data inputs to look at include, capital cost assumptions, fuel costs, generating unit heat rates, O&M expenses, maintenance data, and forced outage rate assumptions
[21] See page 5, Summary Section, Duke Power Company 1997 STAP

and intermediate load units. However, Duke did not indicate how much of the gas-fired capacity will be CT units and how much will be CC Units.

Although there is better consistency among the utilities in the consideration of supply-side resources than in the consideration of DSM options, there are still many options that were not considered by all four utilities. Utilities constantly should re-evaluate technologies as better information becomes available and as costs of various technologies begin to fall. None of the utilities discussed an evaluation of alternative or renewable technologies in their STAPs. It appears that the utilities only considered these technologies in their 1995 IRP studies.

Supply-Side Options

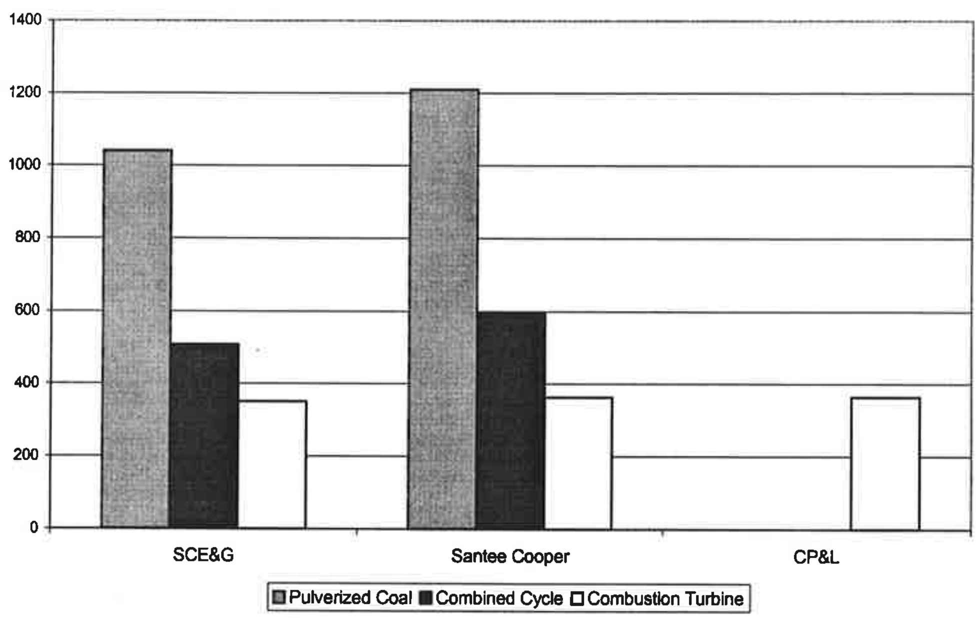
C - Considered, I - Included in Integration, S - Selected in IRP

	CP&L			Duke			Santee Cooper			SCE&G		
	C	I	S	C	I	S	C	I	S	C	I	S
Conventional Technologies												
Advanced Light Water Nuclear Reactor	◆			◆								
Coal Gasification Combined Cycle	◆											
Combined Cycle (CC)	◆	◆	◆	◆			◆	◆	◆	◆	◆	
Combustion Turbine (CT)	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆
Combustion Turbine with Inlet Air Cooling	◆			◆								
Diesel Generator				◆			◆					
Distributed Generation										◆		
Fluidized Bed Coal	◆			◆			◆	◆		◆		
Fuel Cells	◆			◆			◆			◆		
Gas-Fired Boiler				◆								
Integrated Coal Gasification/Combined Cycle				◆			◆	◆		◆		
Oil-Fired Boiler				◆								
Phased Expansion - CT to CC to Coal Gasification				◆								
Pressurized Fluidized Bed Coal				◆			◆	◆				
Pulverized Coal	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆
Supercritical Pulverized Coal							◆	◆				
Energy Storage Technologies												
Advanced Batteries	◆			◆			◆			◆		
Compressed Air	◆			◆			◆			◆		
Lead Acid Batteries	◆			◆			◆			◆		
Pumped Hydro	◆			◆			◆					
Superconducting Magnetic	◆						◆			◆		
Purchases												
Non-Utility	◆			◆						◆		
Utility	◆			◆						◆		
Renewable Technologies												
Biomass – Peat	◆			◆			◆					
Biomass – Wood	◆			◆			◆			◆		
Geothermal	◆						◆			◆		
Municipal Refuse	◆			◆			◆			◆		
Ocean Energy	◆									◆		
Solar – Photovoltaic	◆			◆			◆			◆		
Solar – Thermal	◆			◆			◆			◆		
Wind Power	◆			◆			◆			◆		
Repowering of Existing Plants												
To Coal Gasification Combined Cycle	◆											
To Combined Cycle	◆	◆										
Emerging Technologies												
Advanced Liquid Metal Reactor							◆					
Advanced Pulverized Coal – Chiyoda FGD				◆								
Advanced Pulverized Coal – Spray Dryer FGD				◆								
Evolutionary Advanced Light Water Reactor				◆			◆					
High Temperature Gas-Cooled Reactor				◆								
Integrated Gasification & Humid Air CT				◆								
Passive Advanced Light Water Reactor				◆			◆			◆		
Underground Pumped Storage				◆			◆					
Number of Options	25	4	3	32	2	2	25	7	3	21	3	2

3. Capital Cost Assumptions

The information included in the IRPs and STAPs did not always include the cost assumptions used by the companies. The following chart compares the capital cost assumptions for the supply-side options considered in the Integration step by SCE&G and Santee Cooper along with the CT capital cost used by CP&L in their avoided cost computation.

Expected Capital Costs of Supply-Side Technologies
Dollars/KiloWatt In 1994 Dollars



The estimated costs for CT units are very consistent among the three utilities. However, there are significant differences in the cost of CC and pulverized coal units. The implication here is that either Santee Cooper forecasts a higher cost to build pulverized coal and CC units in their service territory, or they include some costs in their construction cost assumptions that are excluded by SCE&G.

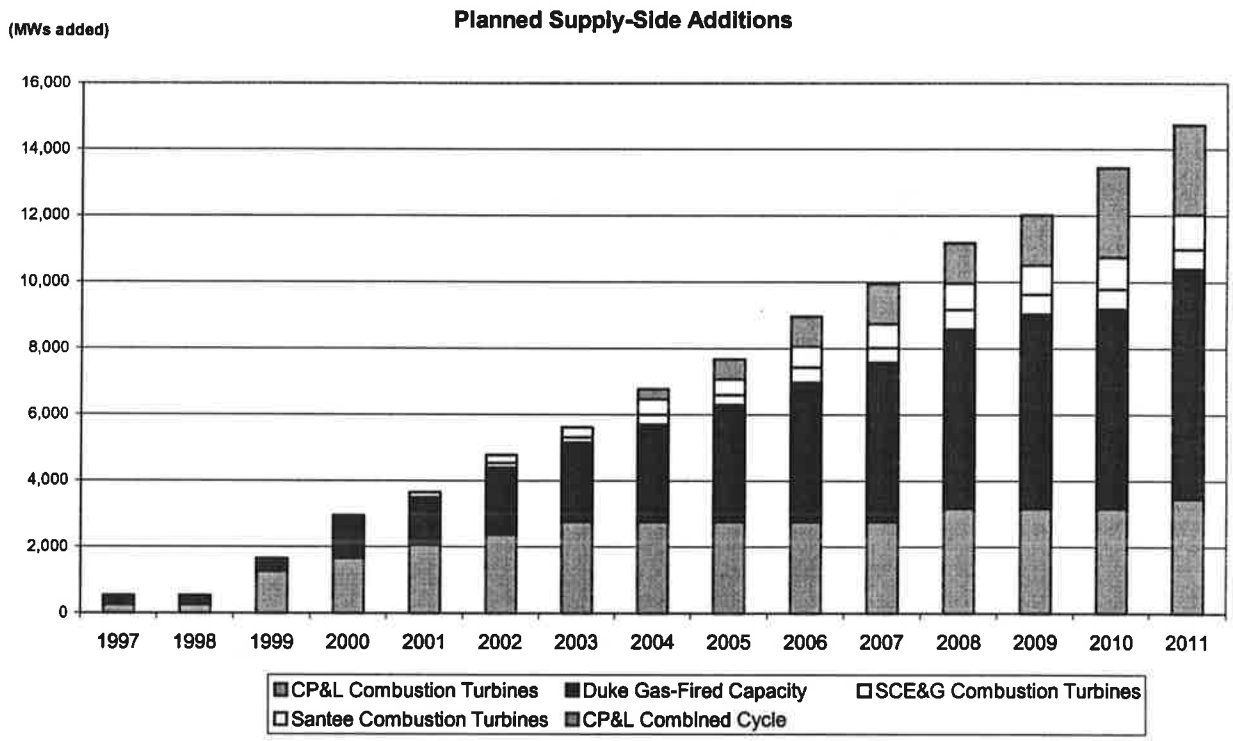
Despite not providing similar capital cost only estimates in $/KW, Duke supplied Screening Curves showing $/KW costs at different levels of capacity factor.[22] Screening curves are useful in that they provide generating unit cost information by combining both operating costs and capital costs into one "Busbar Cost" number that varies by capacity factor. The screening curves that Duke supplied in their 1995 IRP showed that CC units were quite a bit more expensive over the range of 40% - 80% capacity factor than coal units. For example, at a capacity factor of 60% Duke indicated the cost of a 415 MW CC unit was about $315/Kw, while a 600 MW pulverized coal unit was only $275/KW. Even at a lower capacity factor of 40% Duke indicated that the cost of the CC unit was higher, $250/Kw, versus about $220/Kw for the coal unit. This partially explains why

[22] See Page 100 of the Appendix, Duke Power Company 1995 IRP Report

Duke screened out CC units from further consideration, but it also calls into question some of the underlying assumptions used by Duke in their IRP.

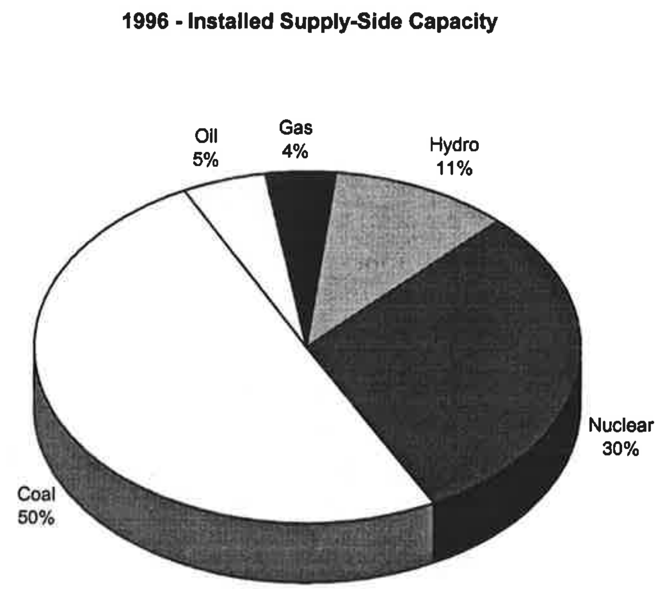
4. Planned Additions

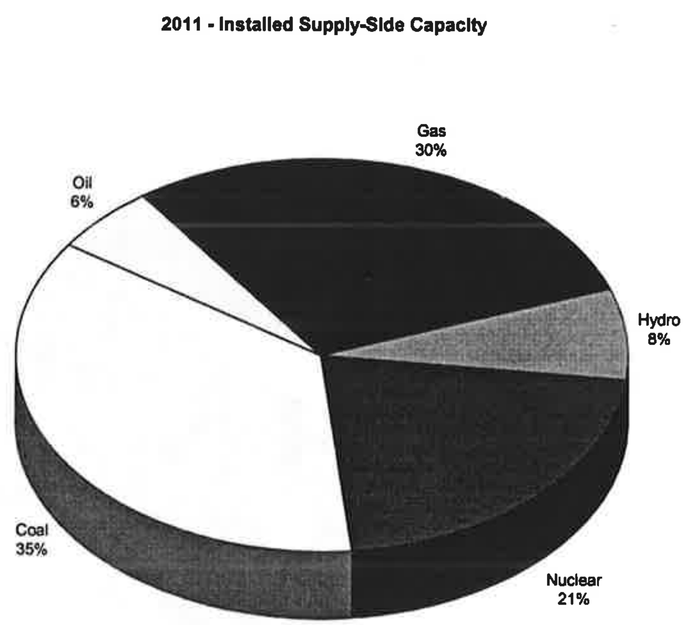
The great majority of planned supply-side capacity additions are CT power plants. Although coal-fired plants and CC plants were selected in several of the original complete IRPs, the changes made in the STAPs result in CP&L and Duke being the only utilities planning any other type of capacity than CT's between now and 2011. However, in the case of Duke Power, they do not clearly indicate how much of their gas-fired capacity additions will be CC and how much will be peaking units. The latest planned additions are shown in the following chart. Note that Duke capacity additions are indicated as being gas-fired capacity.



5. Change in the Mix

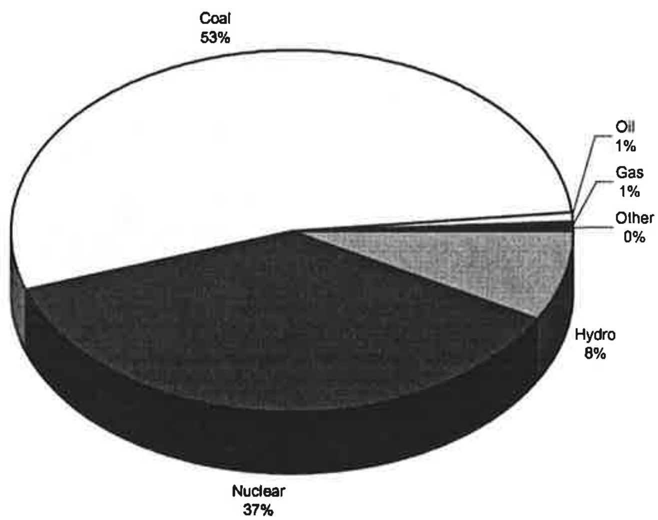
The following pie charts show the change in the installed generating capacity by fuel type from 1996 to 2011, using the planned additions from the latest plans filed by the four utilities.



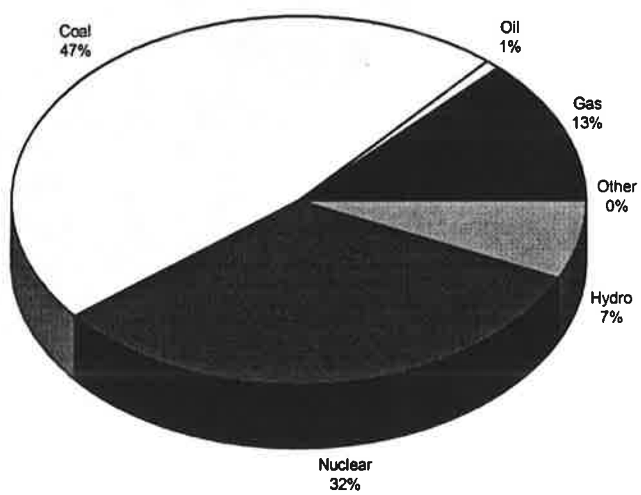


The supply-side capacity mix is transformed from the existing 80% concentration in coal and nuclear to a mix in 2011 that is only 56% coal and nuclear, due to the increase in gas capacity from 4% to 30%. However, since the large majority of the new gas units will be CTs, the energy produced will still be dominated by coal and nuclear. The following charts approximate the energy supplied by fuel type in the years 1996 and 2011.

1996 - Supply-Side Generation Mix



2011 - Supply-Side Generation Mix



The charts shown just above were developed by assuming a typical capacity factor for each generating unit type. For example, it was assumed that all coal plants would operate at a 70% capacity factor. They show that even though the energy produced by gas-fired generation will increase under the current plans, nuclear and coal generation will still produce about 75% of the total energy in 2011.

D. Integration Methodologies and Software Tools

1. General Considerations

Previous sections of this report focused on how the South Carolina utilities analyzed DSM and Supply-Side Options, particularly from the perspective of how they narrowed down to a final evaluation list. This section concerns the results of the Integration Process that the utilities followed in their IRP studies.

As stated previously, each utility may perform an IRP study using different approaches, but similar steps are generally followed including:

- Load Forecast
- Development of Initial Base Supply Plan
- Development of DSM Options
- Development of Supply-Side Options
- Integration Process
- Environmental Consequences
- Risk Analysis
- IRP Selection

The Integration Process requires the use of an optimization software modeling tool.[23] In an earlier section, it was explained that an optimization model is also required to develop the Initial Base Supply Plan. In Section III.B.2 of this report, the procedure to evaluate the cost effectiveness of DSM programs using the Initial Base Supply Plan was discussed. By running an optimization model, considering only supply-side options, an initial expansion plan is created. Based on this reference plan, avoided capacity and energy costs are developed and used in the calculation of cost effectiveness tests.

Two different approaches were used by the South Carolina utilities to perform the Integration. Santee Cooper used a Simultaneous Integration Method and both CP&L and SCE&G used an Iterative Integration Method. Duke Power did not state the method they used to perform the Integration Process.

The primary difference between the two methods relates to the way DSM options are adopted at the completion of the DSM evaluation process. An Initial Base Supply Plan is developed first in both methods. Then DSM program cost effectiveness is determined for all programs. The Iterative Integration Approach adopts cost-effective DSM programs immediately after they are found to be beneficial in the cost effectiveness evaluation step. This approach is iterative, because the next step is to perform another supply-side optimization run to determine if a better supply side plan could be found, given that a series of DSM programs are locked in to the load forecast. Thus the final IRP plan is

[23] See section III.D.4 below for a discussion of the software tools used by the utilities

developed through a process of iterating back and forth between the DSM evaluation and the Supply-Side optimization.

In the Simultaneous Integration method, once DSM programs are found to be beneficial in the cost effectiveness evaluation, they are then packaged into portfolios and treated the same as supply-side options in an optimization run. Thus, the optimization model evaluates both supply and demand-side resource options at the same time, and on a level playing field, and selects the most economical set of resource options.

Another consideration is the optimization technique used in developing the expansion plans. Generation Planning Optimization models attempt to find a least cost expansion plan using the resource options specified and subject to the planning constraints specified for the given run. Despite using different software tools, SCE&G, Santee Cooper, and CP&L all used the Dynamic Programming (DP) optimization technique. Duke did not identify the software tools they used to perform the optimization.

DP Optimization runs can take a long time, and planners have to define constraints to narrow down the combinations of options that can be considered. Some of the constraints that users generally can define include:

- Minimum Reserve Margin
- Maximum Reserve Margin
- Emissions limits
- Emergency energy and Loss of Load Hour Constraints
- Limits on combinations of units that can be built

Typically, generation planners use a Target Minimum Reserve Margin requirement as the primary driver for determining when to add capacity. The minimum reserve margin target establishes the amount of installed capacity above the forecasted annual peak demand that utilities want to plan for in their system expansion studies.

A considerable amount of research has been conducted to determine what the appropriate target minimum reserve margin should be. If set too high, the utility could end up building too much capacity that customers would have to pay for in their rates. If set too low, the utility could end up with higher fuel costs by running older, less efficient plants. Additionally, the utility could incur reliability problems, which would result in excessive financial losses to businesses, not to mention the inconvenience that it would cause to all customers.

2. Reserve Margin Targets

Utilities across the U.S. have typically planned new capacity additions based on target reserve margin criteria of 15 – 22%. These targets have been determined based on characteristics of the system considering such things as how well utilities in the region are interconnected, what type of capacity the utility owns, how old the units are, what kind of unit maintenance program is conducted, etc. The following table provides the reserve margin planning levels that the South Carolina Utilities used in their 1995 IRPs, and in their subsequent STAPs. Santee Cooper and SCE&G did not explicitly state what their reserve margin criterion was, so the values in this table were estimated from other information supplied in their IRPs.

Minimum Reserve Margin Planning Target

Company	1995 Integrated Resource Plan	1996 Short Term Action Plan	1997 Short Term Action Plan
SCE&G[24]	14.4%	14.5%	11.9%
Santee Cooper	17.0%	17.0%	17.0%
CP&L[25]	17.6%	14.9%	14.9%
Duke Power	20.0%	20.0%	17.0%

Another measure of system reliability is the planning criteria called Loss of Load Expectation (LOLE). This is a dynamic measure of reliability that considers not only the capacity and load, but also the availability of generating units. Technically, LOLE is a better measure of reliability because it takes into consideration the condition of generating units in calculating system reliability. Utilities have found it convenient to equate LOLE targets to reserve margin targets.

CP&L was the only company that discussed this reliability measure. In CP&L's 1995 IRP they stated that a 17.6% reserve margin target would provide enough reserves in order to meet the industry standard, one day in 10 year LOLE criteria. By the time they filed their 1996 STAP, CP&L had determined that available spot market capacity would be sufficient to cover their capacity needs so that they could plan for a lower level of reliability of 14.9%.

It has become a common practice in the utility industry to allow the reserve margin criteria to fall, in an attempt to push off decisions about building new capacity as a result of a cloudy deregulation situation. This situation is clearly shown by the regional reserve

[24] SCE&G did not state a Minimum Planning Reserve Margin Target. The reserve margin shown is the lowest reserve margin in any year taken from tables found in SCE&G's 1995 IRP and STAPs.
[25] CP&L states their planning criteria as a capacity reserve margin value of 15% in their 1995 IRP Report. Capacity margin is easily converted to reserve margin, as was done in this table.

margins for the SERC reliability region (which is essentially the Southeast excluding Florida) and the VACAR subregion (which is Virginia, North Carolina and South Carolina):[26]

Year	SERC	VACAR
2000	13.3%	11.6%
2001	12.9%	11.3%
2002	12.5%	10.0%
2006	10.9%	9.8%

It is true that the lowest reserve margins occur in the year 2006, and by then utilities will be able to adjust their expansion plans, but it is of concern that all utilities in the region are allowing their reserve margin to fall in the earlier years as well. Compare these numbers to SCE&G's reserve margin levels. In their 1997 STAP, SCE&G allows their reserve margin target to fall to a level of 11.9% by the year 2003, and to only 12.3% by the year 2001 - only three years from now. This situation does not bode well if load grows at rates much higher than expected.

Utilities have become fearful that building new plants will cause their costs to rise at a time when they are no longer certain of recovering all costs through rates. It should come as no surprise that when all costs plus a return on the investment of building new plants are guaranteed to the utilities, the utilities have no problem advocating higher reserve margins. But when faced with competition, and no guarantee of full cost recovery in rates, then suddenly the utilities see no compelling reason to have such high reserve margin levels.

One argument that utilities make for allowing lower reserve margins today is that with advances in technology, it takes less time to build new plants, and so they no longer need to have such a high reserve margin. While there is some truth to this statement, the fact is that utilities have been building oil and gas-fired CT units for years, and those units always had a much shorter construction time compared to other kinds of plants. The real advantages of new technology lie in generating unit efficiency improvements, not necessarily because of shorter construction lead times.

Another concern is the fact that the spot market was never intended to be a substitute for firm capacity. Planners have always preferred firm capacity to spot capacity in meeting their reliability needs. Even if the assumption is made that enough capacity will be available on the spot market, the cost of that capacity is not easily predicted. Forecasts of market clearing prices do not adequately capture the spikes in costs that occur over

[26] SERC Regional Electric Supply and Demand Projections, June 1997. These reserve margins are based on projected summer peak demand and installed capacity.

short periods when demand shoots up. It remains to be seen whether these spikes will send the proper signals to encourage new capacity to be built at the proper time.

Finally, as deregulation of the utility industry approaches, is it reasonable for utilities to cut their reserve margin targets so significantly, while also reducing their commitment to DSM programs? Implementing a statewide capacity needs assessment would help to address the reliability concerns and promote competition at the same. By informing the merchant plant developers in advance of the need for new capacity, competition would be stimulated among new developers and existing suppliers.

3. Integration Results

As indicated earlier in this report, all of the expansion plans are dominated by gas-fired capacity additions. This is consistent with the plans of other utilities all across the country. Regarding generating unit retirements, SCE&G believes they will be able to extend the life of their thermal units beyond the end of the study period with continued good maintenance practices. Likewise, CP&L only plans to retire a nuclear unit in 2010. Duke and Santee Cooper both show complete generating unit retirement schedules.

The following observations are specific to each utility.

SCE&G Observations

- SCE&G's 1997 STAP only showed an expansion plan that carried out to the year 2007, despite a 15 year IRP reporting requirement.
- SCE&G did not show a need for new generating unit capacity additions before 2002, although SCE&G does show several capacity purchases prior to that time.
- SCE&G assumes that no retirements will occur over the study period.
- SCE&G provides no description of their plans to add 110 MW of Canadys and Westvaco capacity in 1999.
- SCE&G gave no explanation for the 59 MW they added between 1996 and 1997. This capacity addition was evident by comparing their total installed capacity for 1997 reported in their 1996 STAP to their 1997 STAP.
- All planned capacity additions are CT units. This is a little surprising when compared to CP&L's and Duke Power's plan to add both CC and CT units. Perhaps if SCE&G had carried their analysis out beyond 2007, they would have shown some CC additions.

Santee Cooper Observations

- In 1994 when Santee Cooper filed their IRP, one of their large industrial customers, Allumax, had an option to leave Santee Cooper's system. Allumax, with a 300 MW load, has decided to remain a Santee Cooper customer. In Santee Cooper's IRP, they ran a number of scenarios with and without the Allumax load.
- First need for new capacity occurs in 2001.

- All planned capacity additions are CT units, with the exception of a 2012 Pulverized Coal unit, and a 2015 CC unit.
- Santee Cooper carried out their analysis for 21 years.
- Santee Cooper did not update their expansion plan or load forecast in any of their STAPs.
- Santee Cooper is planning to build one or two new units every year. They modeled only 80 MW CT units, while the other utilities modeled CT units that were at least 150 MW. The impact of building these larger CT units should also be reviewed.
- Santee Cooper considered unit retirements during their study period.

CP&L Observations

- CP&L commissioned the new 240 MW Darlington CT unit in 1997.
- CP&L is planning to add 522 MW of CT capacity in Wayne county in 1999.
- CP&L adds a balance of CT and CC units through the study period.
- CP&L is planning to retire the H. B. Robinson Unit 2 nuclear unit in 2010, amounting to a 683 MW reduction in capacity.

Duke Power Observations

- All of Duke Power's capacity additions are planned to be gas-fired. However, Duke did not indicate what kind of gas-fired capacity they were planning. They listed all additions as Peaking/Intermediate. It would have been more useful if Duke would have indicated which units are CT and which are CC additions.
- Duke Power considered unit retirements during the study period.

The follow tables contain the latest expansion plan available from each of the utilities.

CP&L

Year	Peak Demand Forecast[1] (MW)	Cumulative Existing & New DSM Peak Impact[2] (MW)	Net Peak Demand[3] (MW)	Existing Capacity[4] (MW)	Cumulative Capacity Additions (MW)	Description	Cumulative Purchases (MW)	Description	Net Capacity (MW)	Reserve Margin[5] (%)
1997	10764	908	9,856	9613	240	240 MW Darlington CT	1615		11468	13.7%
1998	11072	916	10,156	9715	240		1773	NUG(8),NCEMPA/SCPSA(-50), Peco(200)	11728	12.9%
1999	11344	922	10,422	9715	1262	522 MW Wayne CT	1123	NCEPMPA/SCPSA(-50),Duke(-400),Peco(-200)	12100	13.6%
2000	11635	928	10,707	9715	1662	400 MW CT	1123		12500	14.3%
2001	11900	935	10,965	9715	2062	400 MW CT	1056	NUG (-67)	12833	14.6%
2002	12157	941	11,216	9715	2362	300 MW CT	1024	NUG (-32)	13101	14.5%
2003	12420	946	11,474	9715	2762	400 MW CT	861	NUG (-163)	13338	14.0%
2004	12712	953	11,759	9715	3062	300 MW CC	1061	NCEPMPA Peaking Project (200)	13838	15.4%
2005	13002	959	12,043	9715	3362	300 MW CC	1061		14138	15.2%
2006	13317	965	12,352	9715	3662	300 MW CC	1061		14438	14.8%
2007	13637	971	12,666	9715	3962	300 MW CC	1061		14738	14.3%
2008	13938	977	12,961	9715	4362	400 MW CT	1061		15138	14.8%
2009	14217	982	13,235	9715	4662	300 MW CC	1061		15438	14.7%
2010	14451	987	13,464	9032	5862	1200 MW CC	811	AEP (-250)	15705	14.7%
2011	14704	994	13,710	9032	6162	300 MW CT	811		16005	14.8%

[1] Includes non-controllable load management DSM impacts
[2] Includes Controllable Load Management DSM
[3] This demand includes a 230 MW reduction in peak for Fayetteville Replacement
[4] In 1998 the Brunswick Nuclear units have thermal uprate modifications of 102 MW. In 2010 CP&L is planning to retire Robinson Unit 2, amounting to a reduction of 683 MW of Nuclear capacity.
[5] CP&L does not include the 230 MW reduction in peak for Fayetteville Replacement when calculating reserve margin.

Duke Power Company

Year	Peak Forecast[1] (MW)	Existing Capacity[2] (MW)	Cumulative Retirements[3] (MW)	Cumulative Capacity Additions (MW)	Description	Cumulative Purchases and Sales[4] (MW)	Cumulative DSM Equivalent Capacity[5] (MW)	Total Capacity (MW)	Reserve Margin (%)
1997	17536	19319	0	300	300 MW peak/intermed	-71	985	20533	17.1%
1998	17768	19319	0	300		252	927	20798	17.1%
1999	18087	19319	0	375	75 MW peak/intermed	234	842	20770	14.8%
2000	18721	19319	0	1275	900 MW peak/intermed	634	733	21961	17.3%
2001	18795	19319	0	1425	150 MW peak/intermed	634	637	22015	17.1%
2002	19064	19319	0	2025	600 MW peak/intermed	384	603	22331	17.1%
2003	19374	19319	0	2400	375 MW peak/intermed	384	617	22720	17.3%
2004	19579	19319	-303	2932	532 MW peak/intermed	384	631	22963	17.3%
2005	20040	19319	-391	3532	600 MW peak/intermed	384	641	23485	17.2%
2006	20625	19319	-391	4214	682 MW peak/intermed	384	677	24203	17.3%
2007	21164	19319	-391	4814	600 MW peak/intermed	384	669	24795	17.2%
2008	21680	19319	-476	5414	600 MW peak/intermed	384	731	25372	17.0%
2009	22097	19319	-476	5871	457 MW peak/intermed	384	814	25912	17.3%
2010	22138	19319	-752	6021	150 MW peak/intermed	384	930	25902	17.0%
2011	22541	19319	-1190	6935	914 MW peak/intermed	384	1037	26485	17.5%

[1] Includes Existing DSM, includes Nantahala Power and Light Peak Demand
[2] Includes existing capacity, Nantahala Power & Light Capacity
[3] Buck, Lee, Riverbend CTs in 2004 (303 MW), Buzzard Roost CT in 2005 (88 MW), Dan River CTs in 2008 (85 MW), Dan River 1,2,3 in 2010 (276 MW) and Allen1 & 2 and remaining Buzzard Roost CTs in 2011 (438 MW)
[4] Purchases include SEPA, Cogeneration and SPP units, PECO, Santee Cooper. Sale to CP&L
[5] Duke Power's method of evaluating DSM is to determine a capacity equivalent. Therefore, DSM capacity is added to capacity as opposed to being subtracted from demand

SCE&G

Year	Net Peak Demand Forecast[1] (MW)	Existing Capacity[2] (MW)	Cumulative Capacity Additions (MW)	Description	Net Capacity (MW)	Reserve Margin (%)
1997	3681	4312	34	+ 59 MW No accounting for this cap[3] + 25 MW SCPSA Purchase - 50 MW MEAG Sale, 1 yr only	4346	18.1%
1998	3783	4312	84	+ 50 remove MEAG SALE	4396	16.2%
1999	3893	4312	195	20 MW Canady,91 MW Westvaco	4507	15.8%
2000	3959	4312	195		4507	13.8%
2001	4013	4312	195		4507	12.3%
2002	4083	4312	345	150 MW CT	4657	14.1%
2003	4162	4312	345		4657	11.9%
2004	4225	4312	495	150 MW CT	4807	13.8%
2005	4290	4312	495		4807	12.1%
2006	4361	4312	645	150 MW CT	4957	13.7%
2007	4432	4312	645		4957	11.8%

[1] Includes Interruptible & DSM Capacity
[2] Includes only Existing Generating Units, no Purchases planned, no Retirements planned
[3] 1997 SCEG added 59 MW from their 1996 STAP without any explanation

Santee Cooper With Allumax

Year	Peak Demand Forecast[1] (MW)	Cumulative New DSM Peak Impact[2] (MW)	Interrupt Demand (MW)	Net Peak Demand (MW)	Existing Cap[3] (MW)	Cumulative Retires[4] (MW)	Cum Capacity Additions (MW)	Description	Net Capacity (MW)	Reserve Margin (%)
1995	3056	0	156	2900	3599	0	0		3599	24.1%
1996	3085	7	199	2879	3599	0	0		3599	25.0%
1997	3161	14	199	2948	3599	0	0		3599	22.1%
1998	3179	21	199	2959	3599	0	0		3599	21.6%
1999	3196	29	199	2968	3599	0	0		3599	21.3%
2000	3238	37	199	3002	3599	0	0		3599	19.9%
2001	3309	45	199	3065	3599	-92	160	2 - 80 MW CT	3667	19.6%
2002	3379	54	199	3126	3599	-92	240	1 - 80 MW CT	3747	19.9%
2003	3450	62	199	3189	3599	-92	320	1 - 80 MW CT	3827	20.0%
2004	3549	71	199	3279	3599	-92	480	2 - 80 MW CT	3987	21.6%
2005	3621	80	199	3342	3599	-92	480		3987	19.3%
2006	3699	88	199	3412	3599	-92	640	2 - 80 MW CT	4147	21.5%
2007	3779	96	199	3484	3599	-92	720	1 - 80 MW CT	4227	21.3%
2008	3856	104	199	3553	3599	-92	800	1 - 80 MW CT	4307	21.2%
2009	3935	112	199	3624	3599	-92	880	1 - 80 MW CT	4387	21.1%
2010	4013	120	199	3694	3599	-92	960	1 - 80 MW CT	4467	20.9%
2011	4086	129	199	3758	3599	-92	1040	1 - 80 MW CT	4547	21.0%
2012	4173	138	199	3836	3599	-262	1440	1 - 400 MW PC	4777	24.5%
2013	4261	147	199	3915	3599	-262	1440		4777	22.0%
2014	4351	157	199	3995	3599	-262	1440		4777	19.6%
2015	4443	166	199	4078	3599	-262	1520	1 - 80 MW CC	4857	19.1%

[1] Includes Peak Demand plus existing DSM
[2] Based on recommended TRC/Utility DSM programs
[3] Includes Existing Generating Units plus a 215 MW SEPA Purchase
[4] Jefferies 1 and 2, end of 2000 (92 MW), Grainger 1 and 2 end of 2011 (170 MW), and Jefferies 3 & 4 end of 2015 (306 MW)

4. Integration Process Software Tools

The primary software tools used in the Integration Process are Production Cost Simulation and Optimization Models. These tools work hand in hand. The Optimization Model searches for the optimal resource plan from among all the possible resource expansion plans. For each expansion plan under consideration by the Optimization Model, the Production Cost model simulates the dispatch of the generating units to meet the load requirements.

The following table compares the production cost and optimization simulation software used by the South Carolina utilities.

Comparison of Software Used in the Integration Process

Function	SCE&G	Santee Cooper	CP&L	Duke Power
Production Cost	EGEAS	GAF	WASP/IPM/UPM	Not Stated
Optimization	EGEAS	GAF/PROVIEW	WASP/IPM	Not Stated

UPM – Utility Planning Model – Originally developed by Arthur Andersen for EPRI. Arthur Andersen no longer licenses the model and it is unclear whether any commercial vendor updates the software or provides any maintenance for the tool. Few utilities use UPM today.

IPM – Integrated Planning Model (IPM) was developed by ICF Resources. IPM is a resource optimization tool that has the ability to optimize resources subject to emissions constraints.

WASP III – WASP III was developed by the Tennessee Valley Authority and the Oak Ridge National Laboratory. It was originally developed to assist the International Atomic Energy Agency (IAEA) to perform a market survey for Nuclear Power in Developing Countries. Today, it is primarily used by developing countries that obtain the model for free from the World Bank, and is not widely used by utilities in the U.S. WASP is used to perform supply-side optimization studies. It does not have the ability to consider emission constraints in the optimization process.

E. Risk Analysis

Each utility performed some form of risk assessment as part of their IRP project. The following table contains all of the sensitivity variables that each utility considered.

Risk Analysis – Variables Considered in the IRP

	CP&L	Duke	Santee Cooper	SCE&G
Load Growth	◆	◆	◆	◆
Load Factor		◆		
Nuclear Unit Performance	◆	◆		
Old Fossil Unit Capacity Factor		◆		
Hydro Capacity		◆		
Hydro Energy		◆		
Fuel Costs	◆	◆	◆	
CT Capital Costs	◆	◆	◆	
CC Capital Costs	◆		◆	
Coal Capital Costs		◆	◆	
Nuclear Capital Costs		◆		
Pumped Storage Capital Costs		◆		
Scrubber Capital Costs	◆			
Allowance Costs	◆	◆		
Carbon Tax ($/ton)		◆		
CO2 Emissions Cap		◆		
DSM Levels	◆			
Air Toxins		◆		
Future CT Gas Availability		◆		◆
Jocassee Capacity Increase		◆		

The following are general observations concerning each company's use of Risk Analysis.

1. SCE&G

SCE&G only discussed Risk Analysis from a qualitative perspective. They did not appear to have run any sensitivity cases to obtain the economic impacts of different input assumptions. SCE&G provided a qualitative assessment of the impacts of higher and lower load growth. The conclusion they drew was that their expansion plan could be accelerated or deferred to account for higher or lower load growth.

SCE&G also expressed a concern over potential gas supply reliability problems, given that their entire expansion plan calls for gas-fired capacity. This should be a legitimate concern of all utilities in the region, because all of them are planning so much gas-fired generation that the potential for pipeline limitations might arise. None of the companies looked closely at the issue of there being enough gas capacity to supply the regional demand for gas. The companies took it for granted that gas pipelines would be built to meet the demand. According to SCE&G in their 1995 IRP report, "Reliability of the electric supply for the region and the system will depend directly on reliability of the gas supply to the site."[27]

While the qualitative approach provides some good insight into the nature of SCE&G's system, a more in-depth sensitivity analysis should still be conducted. It would be useful to know how costs of electricity would be affected, for example, if gas prices increase significantly.

2. CP&L

CP&L conducted the best risk assessment of all of the South Carolina utilities, because of the thoroughness of their approach. CP&L performed numerous risk assessment steps including Sensitivity Analysis, Scenario Analysis, Decision Analysis, and Fatal Flaw Analysis. The variables that CP&L evaluated were very comprehensive. The other commendable feature of CP&L's analysis is that they did not just chose the least cost plan from their initial optimization as their IRP. CP&L sought a plan that was as robust as possible based on their comprehensive risk assessment.

Likewise, CP&L selected an SO2 Phase II environmental compliance plan in a similar analysis. Although the least cost plan of action was to purchase emission allowances, CP&L selected a plan that was slightly more expensive on a present worth revenue requirement basis (by $143 million in 1994 dollars).[28] While slightly more expensive than the initial compliance plan, it offers CP&L a degree of flexibility that will be especially useful if and when new NOx and CO2 rules are mandated by the Environmental Protection Agency (EPA).

3. Duke

Duke considered both Sensitivity and Scenario analysis. Based on a comprehensive list of uncertainty variables, they first performed a Sensitivity analysis to determine the ones that had the greatest impact on results.

[27] See page 4.30, SCE&G 1995 IRP Report, Chapter 4 Supply Side Planning.
[28] See page 5-40, Chapter 5 Integration Analysis, CP&L IRP Report

They focused on the following three results that were of particular concern:

- Timing of first base load addition
- Average cost of electricity
- Technology mix

Of all the uncertainty variables that Duke considered, clearly the Carbon Tax variable resulted in the greatest impact on results. It resulted in the biggest change in the expansion plan, had the greatest cost impacts, and forced new capacity additions to be built much earlier in order to displace existing coal capacity.

Duke also conducted a Scenario Analysis to look at the effect of numerous assumptions changing at the same time. The scenarios they chose were:

- Lean and green case
- Intense competition
- Economic boom

Based on these results Duke was able to derive good insight regarding the robustness of their system. Like CP&L, Duke conducted a good risk assessment evaluation.

4. Santee Cooper

Santee Cooper's approach was similar to Duke's. They chose a number of uncertainty variables and then defined several Scenarios to use in analyzing the uncertainty variables.

Santee Cooper also chose to analyze a few special situations, such as cogeneration energy purchases, interruptible load contracts, and extending the life of units they had intended to retire.

F. Environmental Impacts

Each utility addressed environment compliance planning in their IRPs. All of the IRPs covered Phase II SO2 compliance planning and some covered NOx compliance planning. Also, a few of the IRPs covered issues related to Global Warming and CO2 emissions. This section is intended to consider the environmental and economic consequences of the IRP plans of the utilities. Also, this section goes beyond the IRP process by looking at the prominent environmental issues impacting the utilities today, and also considers proposed legislation that is thought to have a chance of passing into law.

This section evaluates the environmental issues confronting the utilities and considers how the impacts will affect residents of South Carolina. These issues are extremely controversial and debates are raging over the accuracy of the science used in the development of various emissions standards. No attempt is made here to add to the debate, instead, the objective is to present a picture of the environmental legislation and regulations that have been implemented and proposed that will impact the electric utility industry.

Issues at the forefront include reducing utility NOx emissions as part of the overall effort to meet the current ozone standard, the revision of the ozone and particulate matter standards, regulation of utility NOx emissions under the acid deposition portion of the 1990 Clean Air Act Amendments, visibility requirements, international negotiations on CO2, and pollution from toxic metals such as mercury.

Congress will address some of these issues in hearings and legislation undoubtedly will be introduced on various topics, especially dealing with the potential environmental consequences of broadened competition in the power generation industry. The EPA also has the authority to set rules that can affect utilities, and finally, states will play a larger role in designing implementation plans that will affect utilities.

Clean Air Act Amendments of 1990

The Clean Air Act (CAA) of 1990 established the most sweeping environmental reforms of this century. The CAA was composed of a number of sections called Titles, some of which were specifically designed to regulate the amount of emissions produced by electric utilities. Specifically, Title I defined National Ambient Air Quality Standards and Title IV addressed problems with acid deposition by controlling utility SO2 and NOx.

The following sections discuss the impacts of environmental compliance planning. They consider both existing rules in effect, and new rules that are being considered by policymakers.

1. National Ambient Air Quality Standards (NAAQS)

Title I of the Clean Air Act Amendments of 1990, requires the EPA to set National Ambient Air Quality Standards for pollutants considered harmful to public health and the environment. The EPA Office of Air Quality Planning and Standards (OAQPS) has set National Ambient Air Quality Standards for six principal pollutants, which are called "criteria" pollutants. They are:

Carbon Monoxide
NOx
Ozone
Lead
Particulate < 10 Micrometers – PM10
Particulate < 2.5 Micrometers – PM2.5
SO2

Of the above pollutants, ozone has clear, documented impacts on human health, crops, and ecosystems. The EPA first promulgated ozone standards in 1971, they amended them in 1979, they revised them again in 1990 with the CAA amendments, and now once again in 1997. More than 3,000 recent studies on ozone have been published, many showing that ozone can cause adverse health effects at levels below the current primary standard. For this reason, the EPA published revisions to the ozone and PM10 standards and developed the PM2.5 standard in July 1997.

Also the EPA revised the primary ozone standard to provide a higher level of protection than the current standard. President Clinton has endorsed the stricter new standards for ozone and fine particles providing the EPA with additional support to confront the multi-million dollar industry campaign against the new standards and widespread opposition among state and local officials.[29]

The following compares the current to the revised Ozone standard.[30]

Current Primary Standard -	1- hour 0.12 parts per million
Revised Primary Standard -	8- hour 0.08 parts per million

[29] American Lung Association, Clinton Endorses Tougher Air Quality Standards, July 1997

[30] The current standard required that daily maximum 1-hour concentration levels not exceed .12 ppm more than once per year, averaged over 3 consecutive years. The revised standard requires the fourth highest daily maximum 1-hour concentration levels not exceed .08 ppm more than once per year, averaged over 3 consecutive years.

Particulate Matter – Up to 10 Microns in Diameter (PM 10)

The particulate matter standards were last revised in 1987. Since that time, many important new studies have been published which show that breathing particulate matter at concentrations allowed by the current primary standard can likely cause significant health effects—including premature death and an increase in respiratory illness.

No change has been specified for the PM 10 standard.[31]

Particulate Matter – Up to 2.5 Microns in Diameter (PM2.5)

The following explains the new PM 2.5 standard. No standards currently exist.

Proposed Annual Standard	-	15 ug/m^3
Proposed 24 hour Standard	-	65 ug/m^3

Each state is required to develop a State Implementation Plan (SIP) which outlines its blueprint for achieving NAAQS within its state boundaries and must be approved by the EPA. As part of these plans, states divide their total area into "Air Quality Control Regions." State and local air pollution control authorities then establish individual requirements for controlling air pollution within each region. During their SIP development, states calculate maximum allowable emission level for each area, evaluate major emission sources and then allocate emission reduction burdens and costs between their inventory of mobile, area, and stationary sources.

If the air quality in a region falls below any of the air quality standards, the EPA designates that region as a "non-attainment area". The area is then required to develop and implement plans to improve its air quality. An approved SIP would contain all required emission reductions to meet ambient air quality standards and to offset all generation/emissions growth.

Overall, the changes to the ozone standard represent about a 10% reduction in acceptable ozone levels. Similarly, the new PM2.5 standards represent a significant overall strengthening of the particulate matter health standard. The EPA believes that over the next two decades, the new standards will lead to significant improvements in public health and a cleaner environment. The EPA estimates that the reductions in particulate matter will prevent 15,000 premature deaths due to lung disease, as well as hundreds of thousands of asthma attacks and tens of thousands of hospital admissions annually across the US.[32]

[31] To attain this standard, the arithmetic average of the 24-hour samples for a period of 1 year, averaged over 3 consecutive years must not exceed 50 ug/m3

[32] Airways, Clinton and Browner Make New Air Quality Standards Official. September 1997

Implementation of the new standards will push many areas of the country currently in attainment of the NAAQS into non-attainment, and push areas already in non-attainment further away from attainment status. States containing non-attainment areas will be forced to implement programs that will reduce particulate matter and ozone pre-cursor emissions. Contrary to the predictions of big business that the new standards will create an economic disaster, the EPA estimates that for every dollar it costs to reduce emissions, seventeen dollars will be saved in health care costs and lost work time.[33]

Focus of Legislation Regarding National Ambient Air Quality Standards

Much opposition exists to the revised EPA standards. Several pieces of legislation have been introduced in both the House of Representatives and in the Senate against the passage of the EPA's final standards for ground level ozone and fine particulates. The following legislation has been introduced into the House of Representatives:

HR 1863 Job Protection Act (Sponsor: Rep. Bob Ney, R-OH)

This would prohibit the Environmental Protection Agency from establishing new standards for ozone or particulate matter before existing standards are attained.

H.R. 1984 (Rep. Klink, D-PA)

This would provide for a four-year moratorium on the establishment of new standards for ozone and fine particulate matter under the Clean Air Act, and would require additional review and air quality monitoring under that Act. Not later than 5 years after enactment of this legislation, the EPA would have to perform a thorough review of the air quality criteria and determine whether to retain such standards or promulgate new standards. The bill specifies provisions related to particulate matter research. The EPA would be authorized to require SIPs to monitor ambient air quality for fine particulate matter. The bill would authorize up to $75,000,000 for research and monitoring in each of the fiscal years 1998 through 2002. Over 120 sponsors have indicated support.

The following legislation has been introduced into the Senate:

S. 1084 -- "Ozone and Particulate Matter Research Act of 1997" (Sponsors James Inhofe, R-OK and John Breaux, D-LA)

This legislation was introduced in late July 1997 to establish a research and monitoring program for the national ambient air quality standards for ozone and particulate matter. The bill differs from H.R. 1984 in three primary ways:

1) It would reinstate the original standards (as opposed to creating a moratorium on the establishment of the new standards, which is moot now that the new standards have been established).
2) Regarding PM research, it would establish an independent panel of scientists under the National Academy of Sciences and an interagency committee.
3) Regarding ozone research, it would establish a research program by the National Institutes of Health to study the health effects of allergens on asthmatics,

[33] Airways, Clinton and Browner Make New Air Quality Standards Official. September 1997

particularly in regards to urban inner city areas (with $25 million authorized to be appropriated for each of the fiscal years 1998 through 2002).

Others in Congress are seeking to delay the adoption of standards for five years, saying they would cost too much and are not based on scientific certainties.

National Ambient Air Quality Standards (NAAQS) impact on South Carolina

South Carolina has four counties that are projected to be in non-attainment with the new air quality standards for ozone and particulate matter. Those counties are: Anderson, Chester, Richland and York.[34]

Research has shown that children, the elderly, and people with asthma, chronic bronchitis, emphysema and heart disease are most likely to suffer health problems when exposed to elevated levels of ozone. In addition to these populations, people with heart disease are also sensitive to elevated particulate matter levels. The State of South Carolina has a total population of 3,663,915. The four counties identified above have a population of 600,639, of these 135,896 (22%) are children and 74,366 (12%) are elderly and 73,714 (12%) have asthma, bronchitis or emphysema.

Richland county is located near Columbia, a major metropolitan area in South Carolina and contains SCE&G's McMeekin and Wateree coal burning generation stations. Duke's WS Lee plant is located in Anderson county. As there are coal burning units located in and near these counties projected to be in non-attainment it is possible that more stringent local controls could be placed on these coal burning generating units in order to allow the affected counties to comply with NAAQS. York and Chester counties are located on the South Carolina border very close to Charlotte, a major metropolitan area in North Carolina.

Evaluation of NAAQS in South Carolina Utilities' IRPs

These issues were not addressed to any significant degree in any of the IRP studies. CP&L provided the most details regarding their consideration of the NAAQS, but they basically said that they are continuing to review the issue and are waiting to see what comes out of the EPA standards setting process, and the SIPs.

If the estimates of health impacts that the EPA has suggested are true then compliance with the more stringent regulations will help to significantly lower health care costs in South Carolina. Utilities will have to play a major role in helping to reduce NOx emissions. As was mentioned in this section, a great debate is already raging over whether the EPA's assessments are realistic.

[34] American Lung Association, Populations at Risk – United States, February 2, 1998

2. EPA Acid Rain Program

The Acid Rain Program was established under Title IV of the 1990 Clean Air Act Amendments. The program calls for major reductions of SO2 and NOx, the pollutants that cause acid rain.

The program sets as its primary goal the reduction of annual SO2 emissions by 10 million tons below 1980 levels across the entire United States and allows flexibility for individual utility generating units to select their own methods of compliance. The program also sets NOx emission limitations (in lb/mmBtu) for coal-fired electric utility units, representing about a 27% reduction from their 1990 levels. The Acid Rain Program is being implemented in two phases: Phase I, affecting a limited number of generating units, began in 1995 for SO2 and 1996 for NOx, and will last until 1999; Phase II for both pollutants begins in 2000 and is expected to involve over 2,000 generating units.

<u>EPA Acid Rain Program - SO2</u>

To achieve the desired SO2 reductions, the law requires a two-phase tightening of the restrictions placed on fossil fuel fired plants.

<u>Phase I</u>

Phase I began in 1995 and affects 263 units at 110 mostly coal-burning electric utility plants located in 21 Eastern and Mid-western states. An additional 182 units joined Phase I of the program as substitution or compensating units bringing the total of Phase I affected units to 445. Utilities were allowed to make cost-effective emissions reductions at substitution units instead of at an affected unit, achieving the same overall emissions reductions that would have occurred without the participation of the substitution unit.

The acid rain program allocated emissions allowances to Phase I units based on the unit's 1985-1987 annual average fuel consumption, authorizing them to emit one ton of SO2 for each allowance. Allowances may be bought, sold or banked within the limits set for an allowance cap and trade program.

By complying with Title IV, Phase I units significantly reduced their SO2 emissions compared to previous years. They emitted 5.3 million tons of SO2 in 1995, 45% less than the 9.7 million tons emitted in 1990 and 40% less than the allowable 8.7 million tons. In contrast, non-Phase I units emitted 6.6 million tons in 1995, 12% higher than the 5.9 million tons they emitted in 1990.[35]

Phase I compliance was not an issue in South Carolina as all of the units were in compliance with Phase I requirements.

[35] Environmental Protection Agency, SO2 Program and Compliance Results 1996

Phase II

Phase II which begins in the year 2000, tightens the annual emissions limits imposed on affected Phase I units and also sets restrictions on smaller, cleaner plants fired by coal, oil and gas, encompassing over 2,000 units in all. The program affects existing utility generating units with a capacity greater than 25 megawatts and all new utility plants.

During Phase II of the program, the CAAA set a permanent ceiling of 8.95 million allowances for total annual allowance allocations to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained.

Phase II Compliance Strategies

Many utilities have not finalized their ultimate Phase II compliance plans. Switching fuels and purchasing allowances seem to be two of the most popular options. One survey of 116 utilities conducted by the Industrial Information Services Company found that 41% of the respondents will switch fuels for Phase II and 28% will acquire additional emission allowances. It is estimated that only 12 to 20 gigawatts of capacity may have flue-gas desulfurization (scrubbers) equipment installed to comply with Phase II requirements, because a number of utilities that had originally planned to install scrubbers have either deferred installation, or canceled them in favor of fuel switching or purchasing allowances.[36]

Estimated SO2 Compliance Costs

Industry-wide annualized compliance costs are estimated at $836 million (1995 dollars). These costs represent only 0.6% of the $151 billion electric operating expenses of investor-owned utilities in 1995. Using scrubbers is estimated to cost $322 per ton of SO2 removal and is the most expensive compliance method. Modifying a high sulfur bituminous coal-fired plant to burn lower sulfur sub-bituminous coal, which is estimated to cost $113 per ton of SO2 removal, is the least expensive method of compliance.[37]

In their 1995 IRP, Santee Cooper estimated that the cost of other compliance options would have to rise to about $200 - $250/ton before a scrubber would be economically feasible.

Impact of Phase II Compliance on South Carolina

All four utilities operating in South Carolina will need to take some compliance action during Phase II.

[36] Energy Information Administration, The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update
[37] Ibid

The following table compares the actual 1995 annual SO2 emissions to the limits established for each of the utilities in the 2000 – 2009 time period.

	Annual Emission Allowances 2000 – 2009	1995 SO2 Emission	Annual Phase II Allowances minus 1995 Emissions
CP&L	143,968	165,034	(21,066)
Duke	185,136	233,483	(48,347)
SCE&G	59,921	82,222	(22,301)
Santee Cooper	42,681	52,435	(9,754)

Although the utility emissions in the 2000 – 2009 time period will most likely be different than what occurred in 1995, this still gives a good indication that all of the South Carolina utilities will be short of allowances in the post 2000 time period. All of the utilities have developed a plan for complying with the Phase II regulations to some degree. The following is a summary of the strategies outlined by each utility in their IRP.

CP&L

CP&L estimates that SO2 emissions will go up to approximately 205,000 tons in the year 2000, greatly exceeding the number of emissions allocated to CP&L (143,968 tons). Therefore, CP&L's emissions are projected to exceed the Phase II allowance base and some compliance action will be required.

CP&L's general SO2 compliance strategy is to increase the use of low sulfur coal, purchase allowances as long as they are more economical than scrubbers, and maintain a scrubber option. Current projections of SO2 emissions show that CP&L can postpone the need to take any actions to reduce emissions until 2004 by using emission allowances already purchased; therefore major financial commitments are not being made at this time. A summary of CP&L's SO2 compliance plan stated in their 1995 IRP plan is presented below:

Generating Unit	SO2 Control Technology	Implementation Year
Asheville 1&2	Switch to compliance coal	1998
All other coal units*	Switch to compliance coal	2000
Mayo 1	Install scrubber & burn 2.1 lbs sulfur coal	2007
Emission allowances	Use existing and allocated allowances	2000
Emission allowances	Purchase more allowances as needed	2007

*Including H B Robinson located in South Carolina

During the 2000 to 2009 time period, projected SO2 reductions of approximately 454,000 tons are to be achieved by switching to lower sulfur coal, 81,000 tons are to be achieved by scrubbing and 395,000 emission allowances will be utilized.

The 1997 STAP states that no new coal capacity is in the current resource plan. CP&L is planning for 2,700 MW of undesignated CT generation and 2,700 MW of undesignated CC generation for the time period 1999 through 2011. This indicates that the SO2 compliance plan should be adequate to the year 2011.

SCE&G

As of the 1995 IRP, SCE&G had purchased sufficient SO2 allowances to meet Phase II limits through 2002. This has allowed SCE&G to postpone making a longer term compliance decision such as installing scrubber equipment.

SCE&G has analyzed the possibility of installing scrubbers at the Williams and Wateree plants as a compliance option. However, they will continue to purchase emission allowances as long as they continue to be more economical than the decision to install a scrubber.

SCE&G's 1996 STAP called for the addition of CT units and capacity purchases until the year 2014 at which time they will add a coal unit. However, for some reason, in SCE&G's 1997 STAP they only evaluated their expansion plan through the year 2007. It is quite likely that they may have pushed out the need for a new coal unit even farther in time. Therefore, their planned expansion plan will have no impact on their SO2 compliance plans.

Santee Cooper

Santee Cooper reviewed the compliance alternatives available to them under a variety of scenarios. Under basecase conditions Santee Cooper will have sufficient allowances until the year 2011. ALUMAX has elected to remain as a customer and therefore, Santee Cooper will be forced to make a compliance decision in 2000. In contrast to the attitude of some of the other utilities, Santee Cooper assumed the utility would not purchase allowances from the market as a compliance option. The options that Santee Cooper will consider are environmental dispatch and installation of a scrubber at an existing unit, most likely Winyah 1.

Duke Power Co.

According to the 1995 IRP Duke's current SO2 compliance strategy is a combination of switching to lower sulfur coal and purchasing allowances. Duke states it is planning to bank allowances before the year 2000. Duke has no plans for adding any baseload generation on their system thereby reducing their need for any dramatic changes in their compliance strategy.

Three of the four utilities discuss obtaining emission allowances to meet Phase II limitations. At this time it appears that this is the most economic option. Allowance prices ranged from $87 per ton to $115 per ton in 1997 compared to over $300 per ton cost of a scrubber and $113 per ton cost to fuel switch to lower sulfur coal.

The regulations for SO2 are very well defined and there are no foreseeable changes to this legislation. In fact, the SO2 allowance trading program has been considered a tremendous success and most participants would like to pattern other emission reduction programs after this program.

SO2 Ranking

The top fifty Eastern electric utilities are responsible for 78% of the national electric industry SO2 emissions. The table below reflects how the utilities in the State of South Carolina rank among the top fifty generating Eastern electric utilities.[38]

	SO2 Emissions							
	Generation (MWH)	Rank	Tons of SO2	Rank	Fossil Emission Rate (lb/MWH)	Rank	Total Emission Rate (lb/MWH)	Rank
CP&L	39,178,524	15	165,034	17	14.05	23	8.44	27
Duke	74,199,222	7	233,483	11	14.40	22	6.32	33
SCE&G	14,722,125	47	82,222	33	17.75	12	11.22	20
Santee Cooper	15,567,174	44	52,435	44	8.43	35	6.74	31

These rankings show that while Duke and CP&L are in the top 20 Eastern states for generation, their emission rates place them in the middle of the pack compared to other Eastern states utilities. SCE&G, while being one of the smallest producers of energy compared to other Eastern states utilities, ranks very poorly in terms of S02 Fossil Emission Rates (only considers generation and emissions from fossil-fueled steam units). Santee Cooper seems to score with excellent results compared to the other South Carolina Utilities.

EPA Acid Rain Program - NOx

NOx emissions are discharged into the atmosphere from various sources, including the burning of fossil fuels by electric utilities. NOx emissions have been shown to have significant adverse effects on human health and the environment. NOx contributes substantially to ozone formation, acid deposition, acidification of water bodies, inhalable fine particle formation, and visibility degradation. Higher ozone levels cause increased asthma attacks, reduced pulmonary function, coughing and chest discomfort, headache

[38] Benchmarking Air Emissions of Electric Utility Generators in the Eastern United States, by Natural Resources Defense Council, Public Service Electric and Gas Co. and Pace University's Mid-Atlantic Energy Project , April 1997

and respiratory illness. Electric utilities account for 30% of NOx emissions nationwide, and approximately 90% of electric utility NOx comes from coal-fired power plants. [39]

The Clean Air Act Amendments (CAAA) of 1990 set a goal of reducing NOx emissions by 2 million tons from 1980 levels. Title IV of the CAAA required the EPA to establish NOx annual average emission limits (in pounds of NOx per mmBtu of fuel consumed). The Acid Rain Program focuses on one set of sources that emit NOx, coal-fired electric utility boilers. The NOx program is implemented in two phases beginning in 1996 and 2000.

Phase I

Phase I of the program began on January 1, 1996, and affects specific types of boilers in steam generator power plants known as Group I boilers (dry bottom wall-fired and tangentially fired). The Phase I emission limits are:

Phase I Emission Limits

Group 1 Boilers	**Limits (lb/mmbtu)**
Dry bottom wall fired	.50
Tangentially fired	.45

The EPA has confirmed that most Group 1 boilers can achieve individual unit limitations as outlined above using commercially available technology. Options for compliance with the emission limitations include:

1. Meet the standard annual emission limitations.
2. Average the emissions rates of two or more boilers, which allows utilities to over-control at units where it is technically easier and less expensive to control emissions.
3. If a utility cannot meet the standard emission limit, it can apply for a less stringent alternative emission limit (AEL) if it uses the appropriate NOx emission control technology on which the applicable emission limit is based.

Approximately 170 boilers across the US must comply with these NOx performance standards during Phase I. There are no Phase I boilers in South Carolina.

Phase I compliance is intended to reduce annual NOx emissions in the United States by over 400,000 tons per year between 1996 and 1999 from what emissions would have been without EPA requirements.[40]

[39] Environmental Protection Agency, NOx Reduction Program Final Rule for Phase II (Group 1 and Group 2 Boilers)
[40] Environmental Protection Agency, 1996 Acid Rain Compliance Report

Phase II

As part of the Phase II regulations, the EPA decided to tighten the NOx emission limits for Group 1 boilers because of currently available data on the effectiveness of NOx emission reduction technology, such as Low NOx Burner (LNB) equipment. Phase II compliance of Group 1 boilers is intended to reduced annual NOx emissions by approximately 1.17 million tons per year beginning in the year 2000.[41] In addition, Phase II regulations established initial NOx emission limits for Group 2 boilers, which include boilers applying cell-burner technology, cyclone boilers, wet bottom boilers and other types of coal-fired boilers.

The following table presents the boiler types affected by this rule, and the NOx emission limitations:

Phase II Emission Limits

Group 1 Boilers	**Limits (lb/mmbtu)**
Dry bottom wall fired	.46
Tangentially fired	.40

Group 2 Boilers	**Limits**
Cell Burners	.68
Cyclones > 155 MW	.86
Wet Bottoms > 65 MW	.84
Vertically fired	.80

By the year 2000, the Phase II regulations will achieve an additional reduction of 890,000 tons of NOx annually thereby increasing the total expected NOx emission reductions under Title IV to 2,060,000 tons annually after the year 2000.[42] The annual cost of these additional reductions is estimated to be approximately $200 million, at an average cost-effectiveness of $229 per ton of NOx removed. The emission limitations established by this rule are some of the most cost-effective means of achieving NOx reductions when compared to the average cost of removal per ton for Industrial NOx controls ($2,000) and automobile NOx controls ($7,000).[43]

[41] Environmental Protection Agency, 1996 Acid Rain Compliance Report
[42] Ibid
[43] Ibid

Impact of NOx Compliance on South Carolina Utilities

CP&L

Incorporated into the CP&L IRP is a preliminary compliance plan for NOx regulations. CP&L has one coal unit in the State of South Carolina, HB Robinson and plans on installing an LNB System by the Spring of 1998.[44]

	Boiler Type	NOx Total (Tons)	Total Rate (lb/mmBtu)
HB Robinson 1	Tangential	2733	0.682

The current NOx emission rate for HB Robinson violates Phase II emission limits, however, the planned installation of an LNB should bring the unit into compliance.

SCE&G

SCE&G and The South Carolina Generating Company (the owner of Williams station) state that they intend to spend More than $200 million dollars in the next ten years to reduce NOx and SOx emissions. With respect to NOx SCE&G continues to study compliance strategies such as installing LNBs at some or all plants. They will not make a final decision until the EPA promulgates final rules.

However, given the types of boilers utilized at SCE&G's coal-fired plants and the Phase II limitations outlined above, none of the SCE&G units identified currently will comply with Phase II regulations. Some type of low-NOx burner technology will have to be installed to comply with the Final Phase II NOx restrictions.[45]

[44] EPA Acid Rain Program, 1995 and Historic NOx emission Data for Coal-Fired Power Plants
[45] Ibid

	Boiler Type	Controlled/ Uncontrolled	NOx Total (Tons)	Total Rate (lb/mmBtu)
Canadys 1	Tangential	U	1712	0.509
2	Tangential	U	2389	0.565
3	Dry Bottom WF	U	4989	0.998
McMkin1	Tangential	U	3140	0.622
2	Tangential	U	1869	0.611
Urquhart1	Tangential	U	1358	0.635
2	Tangential	U	1284	0.573
3	Tangential	U	2038	0.635
Williams1	Tangential	U	12690	0.730
Wateree 1	Dry Bottom WF	U	9389	1.019
2	Dry Bottom WF	U	13434	1.177

At the time SCE&G submitted their IRP, the EPA had not defined Phase II NOx emission limits. SCE&G was not forced to commit to any definite compliance plan as far as NOx emissions was concerned. However, they will now have to form a strategy to comply with the recently promulgated restrictions as none of their units with the exception of the recently commissioned Cope station operate with any type of LNB technology.

<u>Duke</u>

The Duke Power IRP states that in order to meet Title IV Phase II (year 2000) annual emission limitations Duke must reduce NOx emissions between 20 to 30 percent from current levels (1995). Duke also indicates that it plans to modify boiler operations to lower NOx by installing LNB technology before 1997.

The 1996 and 1997 STAPs indicate that a detailed compliance plan for Phase II requirements has been developed, although they do not explain any of the details. It is evident that some type of LNB technology will have to be installed in order for the Lee units to meet Phase II NOx requirements.[46]

[46] EPA Acid Rain Program, 1995 and Historic NOx emission Data for Coal-Fired Power Plants

Unit		Boiler Type	Controlled Uncontrolled	NOx Total (Tons)	Total Rate (lb/mmBtu)
WS Lee	1	Tangential	U	442	0.662
	2	Tangential	U	405	0.618
	3	Tangential	U	1087	0.646

Santee Cooper

Santee Cooper has estimated their units NOx emissions out to the year 2015 as presented in Table VI-5 in their 1995 IRP. They state that the scope of the IRP was only to identify the NOx emissions for Santee Cooper's units and not to determine if they are in compliance, or to identify a compliance plan if they are not. However, they do present some pertinent information. The Winyah 2, 3 and 4 units have installed LNB equipment. The Jefferies and Grainer units will have LNB technology installed before January 1, 2000. The Cross units are very close to complying and already have LNB technology installed.[47]

Unit		Boiler Type	Controlled Uncontrolled	NOx Total (Tons)	Total Rate (lb/mmBtu)
Cross	1	Dry Bottom WF	LNBO	4425	0.315
	2	Tangential	LNC1	7333	0.439
Grainer	1	Dry Bottom WF	U	704	.819
	2	Dry Bottom WF	U	779	.889
Jefferies	3	Dry Bottom WF	U	3696	0.999
	4	Dry Bottom WF	U	4106	1.004
Winyah	2	Dry Bottom TF	LNBO	4122	0.541
	3	Dry Bottom TF	LNBO	3270	0.584
	4	Dry Bottom TF	LNBO	3581	0.526

LNCO Low NOx Burner with overfire air
LNB1 Low NOx Coal and overfire air option 1

The Santee Cooper units appear to be on track to meet Phase II NOx limitations. Even if they fail to meet the Phase II actual restrictions they may apply for AEL as they have installed or plan to install LNB technology at all of their units by 2000.

[47] EPA Acid Rain Program, 1995 and Historic NOx emission Data for Coal-Fired Power Plants

EPA Acid Rain Program - NOx Summary

The heavy use of coal by Southeastern utilities contributes to high emissions of NOx in the Southeast. The chart below indicates the rankings of the utilities operating in the State of South Carolina. With respect to NOx Fossil Emission Rates, (only considers generation and emissions from fossil-fueled steam units) Duke, CP&L and SCE&G rank 4th, 7th, and 8th respectively out of the 50 largest generating companies in the Eastern United States.[48 49]

	NOx Emissions							
	Generation (MWH)	Rank	Tons	Rank	Fossil Emission Rate (lb/MWH)	Rank	Total Emission Rate (lb/MWH)	Rank
CP&L	39,178,524	15	108,301	12	9.22	7	5.54	17
Duke	74,199,2222	7	155,527	6	9.59	4	4.21	23
SCE&G	14,722,125	47	41,604	35	8.98	8	5.68	15
Santee Cooper	15,567,174	44	33,057	38	5.31	33	4.25	21

With respect to NOx emissions, Duke, CP&L and SCE&G have some of the highest emission rates compared to other utilities in the Eastern States. Once again Santee Cooper has some of the lowest NOx emissions rates.

Even though it appears that the utilities in South Carolina will not have a problem complying with the NOx restrictions outlined in Title IV of the CAAA by installing currently available LNB technology, they may have a problem meeting more stringent limitations that are under consideration by the EPA.

3. Global Warming – CO2

The issue of global climate change has become the focus of intense debate both domestically and internationally. Some scientists have long speculated that emissions from burning coal and other fossil fuels would lead to global warming. Emissions of CO2 intensify the earth's natural greenhouse effect and thus warm the planet. CO2 and other greenhouse gases have been building up rapidly in our atmosphere, primarily due to deforestation and the burning of coal, oil, and gasoline in power plants, automobiles, and industries. These polluting activities currently release over 25 billion tons of CO2 into our atmosphere annually, and natural processes are unable to absorb all of what we emit.

[48] Note: Information for Duke and CP&L includes generation for all of Duke and CP&L, not just that portion that falls within South Carolina borders.

[49] Benchmarking Air Emissions of Electric Utility Generators in the Eastern United States, by Natural Resources Defense Council, Public Service Electric and Gas Co. and Pace University's Mid-Atlantic Energy Project , April 1997

Many scientists are in disagreement, and believe that the scientific evidence does not support the conclusion that CO_2 emissions are causing the earth's temperature to rise.

In 1992, prompted by mounting scientific evidence that global warming is under way and that serious action will be required to mitigate dangerous future climatic changes, the United States, along with roughly 150 other nations, signed the United Nations Framework Convention on Climate Change (FCCC) at the Earth Summit in Rio de Janeiro. The FCCC was ratified by the U.S. Senate in 1992 and has now been ratified by 166 nations altogether.

As a result of signing this treaty, the most industrialized nations, including the world's leading emitter of greenhouse gases, the U.S., agreed to voluntarily reduce emissions back to the 1990 levels by the year 2000. However, the U.S. and most other industrialized nations are not on course to meet this target, in fact, at the current rate emissions in the U.S. are projected to be 13% higher in the year 2000 than they were in 1990.

Because these voluntary targets have proven inadequate in curbing emissions growth, there is now widespread agreement that legally binding measures are necessary. In December 1997, another Earth Summit was held in Kyoto Japan. At the Summit, an agreement was reached which called for the U.S. to trim greenhouse gas emissions by 7% from 1990 levels between 2008 and 2012. Even before it was approved, the proposal was vigorously opposed by Congress and the electric utility industry. The reductions would be achieved largely by burning less coal, and more natural gas.

President Clinton has announced that he will not submit the Treaty for ratification to Congress until 1999, by which time he hopes to wring from developing countries a pledge to limit their greenhouse gases, alleviating the major objection to the treaty. The fear is that if America's competitors don't have to meet the Kyoto goals, industries will move plants and jobs overseas. [50]

A study for the European Union (EU) indicated that EU nations would lose about 1.6% in total economic output in 2010 while the U.S. could lose less than 1% in meeting the requirements of the Treaty. But the conservative Heritage foundation in Washington, in its own outlook, said U.S. drivers could pay an extra 70 cents a gallon for gasoline and electricity prices would rise by between 40% and 50%.[51] Duke Power performed a sensitivity study in which they modeled a $100/ton carbon tax and found that total present worth of revenue requirements increased by 30%.

It is not yet completely clear in what way the Kyoto Protocol will affect the electric utility industry. However, electric utilities are responsible for 36% of CO_2 emissions.[52]

[50] Utility Spotlight, Administration Deregulation Plan Finally Disclosed: Mixed Reaction, March 31, 1998
[51] Kyoto Treaty of Uncertain Outlook; Should Be costly to Electric Industry
[52] Natural Resources Defense Council, Benchmarking Air Emissions of Electric Utility Generators in the United States. April 1997.

Recommendations relating to the electric industry for reducing the emission of CO2 include:

- Run power plants more efficiently. The Clinton Administration recently announced its plan for electric utility competition citing an objective of more efficient use of power plants. The industry average generating unit efficiency rate stands at 34%, but the best plants run at 55% efficiency. The Clinton administration believes that through competition, the efficiency of generating units will increase. They estimate that the plan will reduce greenhouse gas emissions by 25 to 40 million metric tons by the year 2010.[53]

- Require utilities to offer green marketing programs. People who want to support renewables such as wind might be willing to pay more. Several utilities around the country already have "green pricing" programs in place. For example:

  Public Service Co. of Colorado. The RET Round-Up Program rounds customers' monthly bills up to the nearest dollar to support renewable electric generation.

  Traverse City Light and Power . The Green Rate Wind Project supplies consumers with electricity from a 600-kW wind turbine for 8.3 cents/kWh (a 1.58 cent/kWh premium.

  Niagara Mohawk Power Corp. The GreenChoice Program charges a fixed premium of $6.00 per month. Five-sixths of the net funds are spent on renewable energy projects, and one-sixth is spent on tree planting.

  Wisconsin Electric Power Company. WEPCO gives customers the option of purchasing 100, 50, or 25 percent of their electricity at an additional rate of 2.04 cents per kWh from hydro dams and biomass plants that burn wood pulp that would otherwise go in a landfill.

- Replace half of the coal-fired electric generating plants 35 years or older with new CC natural gas units and convert half of all other coal-fired plants to burn natural gas at a cost of $25 per ton of carbon saved.[54]

- Invest in the estimated full potential for wind electric turbines (23 gigawatts) at an average cost of $21.50 per ton of carbon saved.

[53] Newsweek, Wake Up Call. December 22, 1997.
[54] Alliance to Save Energy and Business for Sustainable Energy, It Doesn't Have to Hurt. 1997

Impacts of C02 Restrictions on South Carolina Utilities

In their 1995 IRP, Duke Power states that it has worked with the Department of Energy and others in the utility industry to develop the Climate Challenge Program. In 1995 Duke negotiated a Participation accord with the DOE to voluntarily limit the growth of greenhouse emissions by evaluating and implementing cost-effective initiatives. Additionally, Duke performed a Carbon Tax Sensitivity Case in which they assumed a cost of $100/ton for carbon emissions. Under this case, Duke concluded that nuclear power becomes a viable alternative to conventional pulverized coal, with a 30% increase in new present value revenue requirements.

CP&L acknowledges that greenhouse gas legislation would have an impact on their resource plan. To meet the requirements, they would have to consider technologies that do not produce CO2, such as nuclear power, or that reduce CO2 emissions such as the conversion of older coal units to burn natural gas.

Santee Cooper did evaluate the impact of a carbon tax. In their case they assumed a tax of $30/ton of carbon emissions. The result of their analysis showed about an 11% increase in net present value revenue requirements.

SCE&G did not mention any incorporation of CO2 emissions limiting legislation into their IRP process.

It is not surprising that the global warming issue was not examined further in the utilities IRPs in 1995. SO2 and NOx legislation was a much more pressing issue. However, the CO2 emissions issue has come off the back burner and is currently being defined.

With the exception of CP&L, the South Carolina utilities rank favorably against the top fifty generating utilities in the Eastern United States, concerning CO2 emissions.[55]

	CO2 Emissions							
	Generation (MWH)	Rank	Tons	Rank	Fossil Emission Rate (lb/MWH)	Rank	Total Emission Rate (lb/MWH)	Rank
CP&L	39,178,524	15	2,266	18	2,266	17	1,361	35
Duke	74,199,222	7	2,138	12	2,138	32	938	37
SCE&G	14,722,125	47	2,102	46	2,102	37	1,329	45
SCPSA	15,567,174	44	2,002	42	2,002	42	1,601	28

[55] Benchmarking Air Emissions of Electric Utility Generators in the Eastern United States, by Natural Resources Defense Council, Public Service Electric and Gas Co. and Pace University's Mid-Atlantic Energy Project , April 1997

4. Ozone Transport Assessment Group (OTAG)

Ground-level ozone, or smog, is formed when NOx (emitted from automobiles, power plants, and other sources) and volatile organic compounds react in the presence of sunlight. The smog that results causes numerous health related problems such as serious respiratory illness, damage to lung tissue, and cause significant declines in agricultural crop yield.

Ground level ozone can become a problem over broad regional areas, and has become of particular concern to the Eastern United States. It is alleged that ozone can be transported hundreds of miles and, as a result, can affect public health in other states far away from the source of the pollution. Thus, areas with "clean" air, those that meet or attain the national air quality standards for ozone, may actually contribute to a downwind region's ozone problem because of transport.

In May 1995, the EPA and the Environmental Council of States (includes commissioners from each state) formed the Ozone Transport Assessment Group (OTAG). Comprising the 37 Eastern-most States and D.C., OTAG was created to develop strategies that address the transport of smog forming pollutants across state boundaries.

The findings of OTAG were that an 85% reduction in utility NOx emissions are required to reduce Ozone formation to acceptable levels. To determine whether upwind sources contribute significantly to poor air quality in an area downwind, the EPA relied heavily on the technical information developed by the OTAG. Opponents of the OTAG recommendation disputed the findings and claimed the modeling results did not prove that long-range transport of NOx emissions was occurring. They say even modeling a stringent 85% utility NOx reduction requirement throughout the 37 states did not result in ozone attainment, and the impacts in the Amtrak Corridor were not "significant". Regional modeling runs were even more conclusive. The Southwest and Southeast did not impact the Northeast, nor did Midwest controls result in "significant" impacts in Northeast air quality. The evidence soon caused discussions that the so-called course grid states (all of North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Arkansas, Louisiana, Mississippi, and Florida, and portions of Maine, New Hampshire, Vermont, New York, Michigan, Wisconsin, Missouri, Alabama, and Georgia) should be exempted from OTAG-related controls.[56]

Nevertheless, the EPA has proposed to require the remaining 22 states (including South Carolina) to submit SIPs that address the regional transport of ground-level ozone. By improving air quality and reducing emissions of NOx, the actions directed by these plans are expected to decrease the transport of ozone across state boundaries in the

[56] Center for Energy and Economic Development, OTAG Wrap-up: EPA Moves to SIP-CALL. June 1997.

Eastern half of the United States. The 22 states have been identified as those that "contribute significantly" to ozone problems in downwind areas.[57]

As far as utilities in the 22 states are concerned the OTAG Policy Group recommends that the range of utility NOx controls fall between Clean Air Act controls and the more stringent 85% reduction from the 1990 rate (lb/mmBtu) or 0.15 lb/mmBtu.

The EPA is issuing a NOx budget for each identified state in the proposed rule. Budgets were established based on recommendations from OTAG on how to reduce emissions from utilities and other sources of NOx. States have the flexibility to decide which utilities and other sources will be required to reduce NOx emissions. State plans are to be submitted to the EPA by September 1999, and plans are to be implemented by September 2002.

Impacts of OTAG Restrictions on South Carolina Utilities

Presented in Section III.F.3 above is a compilation of the NOx total tons and the NOx emission rate for each coal unit for each utility in South Carolina. Compared to the proposed 0.15 lb/mmBtu NOx emission rate, all coal units in the State of South Carolina would be in violation of the standard.

The State of South Carolina is targeted to reduce its NOx emissions by 31%. The EPA estimates the proposed requirements would cost the nation about $2 billion a year to implement, which amounts to about $1,700 per ton of pollution removed. Much of that bill would be picked up by electric utilities.[58]

The estimated impact on the State of South Carolina regarding compliance is significant. One estimate claims, that an 85% reduction in NOx or 0.15lb/mmBtu NOx emission limitation, without an emission trading program would cost $80,134,000. The projected net job losses would be approximately 6,799 people in South Carolina.[59] However, it seems unlikely that there would such a dramatic job loss if $80 million were spent to reduce NOx emissions. Nevertheless, once again, the success of the SO2 allowance trading program suggests that if such stringent NOx emission reductions are implemented, an emission trading program would be a much more efficient way to implement the limits, to minimize the impact on the South Carolina economy.

[57] Office of Air Quality Planning and Standards, Proposed Rule for Reducing Regional Transport of Ground-Level Ozone (Smog): October 10, 1997.
[58] Public Utilities Fortnightly, NOx Joke EPA Has IOUs Fuming, November 15,1997.
[59] Midwest Ozone Group, Threat of Section 126 Petitions To South Carolina.

IV. IRPs of Other States

A. Wisconsin

The IRP process in Wisconsin has evolved into a true statewide planning process since the process was initiated in 1986. Each of the utilities produce their own IRPs, and then one plan, known as the Advance Plan, is published by the Public Service Commission of Wisconsin. The Advance Plan is a joint IRP for the following utilities:

- Badger Power Marketing Authority of Wisconsin
- Dairyland Power Cooperative
- Madison Gas & Electric
- Northern States Power Company – Wisconsin
- Superior Water, Light & Power Company
- Wisconsin Electric Power Company
- Wisconsin Power & Light Company
- Wisconsin Public Service Company

Previously, the Advance Plan identified the timing and level of the utilities' future capacity additions, while today the Advance Plan is considered a strategic planning tool to identify capacity needs in advance and initiate a bidding process to satisfy those needs. In this way, the process can be viewed as providing the merchant plant industry with indications of market opportunities for the State of Wisconsin as a whole. The Advance Plan is subject to review and approval by the Wisconsin PSC and becomes a binding document, unless approval for a modification is granted.

1. Demand-Side Management

The Wisconsin utilities are national leaders in DSM achievements, as shown in the following table:

	Energy Savings		Peak Demand Savings	
	Ranking	Savings	Ranking	Savings
Highest Achievement	1	7.3%	1	20.9%
Wisconsin Electric Power Company	6	5.9%	9	12.5%
Wisconsin Public Service Company	14	4.7%	10	11.9%
Wisconsin Power & Light Company	26	2.8%	48	3.7%
Lowest Achievement	127	-3.3%	127	0.0%
Average Achievement		1.3%		4.0%

2. Generation

All new supply-side resources are to be acquired through a competitive bidding process. It is apparent that the PSC prefers that new supply-side generation be constructed as merchant power plants, that is, plants owned and operated by Independent Power Producers, rather than the regulated utilities.

3. Environmental

Wisconsin is a leader in environmental issues. As a part of the PSC-mandated process, each utility is required to develop several plans. One of the required plans must use the following monetized externality values for CO2, Methane and Nitrous Oxide emissions:

- CO2 - $15 per ton
- Methane - $150 per ton
- Nitrous Oxide - $2,700 per ton

Using these monetized externalities causes the selection of additional CC units in place of CT units, and in effect displaces existing coal unit generation with new CC unit generation.

4. Relevance to South Carolina

Several features of the Wisconsin process appear to have value that would improve the South Carolina IRP process:

- PSC approval is required
- A common IRP computer model is employed
- Monetization of environmental externalities is required
- The transition to deregulation has been considered

The Wisconsin PSC Staff plays an important role in the generation of the statewide plan, working with the utilities to agree on a final plan. This, along with the fact that PSC approval is required, makes the IRP process serious and meaningful.

To facilitate and simplify the joint-planning process, all of the utilities and PSC Staff use a common IRP software tool – EGEAS, which was developed by EPRI and is available at no cost to all EPRI members. Thus all data used in the IRP process is easily identified and compared.

The development of a plan that is based on the monetization of environmental externalities is required by the South Carolina IRP legislation, but it is generally ignored by the utilities here. Requiring PSC approval for any IRP would likely cause all utilities to take this requirement more seriously. Also, if the South Carolina PSC would develop monetized externality values, the process would be facilitated.

Finally, the Wisconsin PSC, well aware of the national move towards electric deregulation, has modified the IRP process in that state to become a process that informs and encourages the merchant plant industry to develop the power plants that will be needed to maintain a reliable electric supply in Wisconsin. This is one possible scenario for the IRP process in South Carolina as the state approaches deregulation.

B. Georgia

The first IRPs in Georgia were filed in 1992. Since that time, IRPs have been filed in both 1995 and 1998. Only Georgia Power Company and Savannah Electric Power Company (the investor-owned utilities in the state) are required to file.

To receive PSC approval to construct new generating capacity or initiate DSM programs, the utilities must show that the requested resource is consistent with the currently approved IRP. That is, the IRP legislation in Georgia requires that the utilities file and gain PSC approval for their IRPs.

1. Demand-Side Management

The 1992 IRPs included aggressive DSM plans approved by the Commission. However, the 1995 IRPs essentially removed the original level of DSM from the companies plans, based on arguments by the Companies that the original levels of DSM would have significant upward impacts on customer rates. Currently the companies utilize the RIM test to screen potential DSM programs. Georgia Power initiated a pilot residential load control program in 1997.

2. Generation

After the approval of the 1992 IRPs, the Georgia PSC added the requirement that all new supply-side capacity additions be acquired through a competitive bidding process, overseen by the Commission Staff. Several acquisitions have been made through this process. The Companies are allowed to bid a "self-build" proposal in the process, but are not allowed to bias the process toward their proposal.

3. Environmental

Although the IRP rules require that a plan be developed using environmental externalities, the companies have successfully avoided providing such plans by arguing that the monetization of environmental externalities is far too speculative to be used. The IRPs approved to date have not been based on monetization of environmental externalities.

4. Relevance to South Carolina

At least the following points concerning Georgia's IRP process would be useful to consider in South Carolina:

- All IRPs must be approved by the PSC
- Any new supply-side additions must be obtained through competitive bidding
- Attempts to monetize externalities were abandoned due to a lack of agreement by utilities on what monetized externality values should be.

- Both Staff and the utilities utilize the same IRP model

Concerning the last point, since Georgia Power and Savannah Electric are subsidiaries of Southern Company, the IRP models are those used by Southern Company – PROSCREEN II and PROVIEW, commercially licensed products of New Energy Associates, Inc. To simplify the verification and modification process, the Georgia Staff has also licensed PROSCREEN II and PROVIEW. Georgia Power and Savannah Electric simply provide (under a confidentiality agreement) their PROSCREEN II and PROVIEW data to Staff.

C. Virginia

Virginia Power, in its 1997 IRP, states that it is "planning for the future based on the assumption that retail competition will eventually be authorized in Virginia." The Company's philosophy and general planning practices are mainly based upon this assumption.

Growth in peak demand is forecasted to be 1.7% per year over the next ten years, while growth in annual energy requirements is forecasted at 2.2% per year over the same period. These growth rates are very similar to those of the South Carolina utilities.

1. Demand-Side Management

Virginia Power, in a mode similar to the South Carolina utilities, plans to reduce its demand-side portfolio over the next few years. Where there were nineteen DSM programs in the 1996 plan, the 1997 plan includes only eight. In addition, four of the eight remaining programs are load-building programs that result in increases, rather than decreases in the peak demand and energy requirements. The net impact on both peak demand and annual energy requirements in future years is a significant increase.

2. Generation

On the supply-side, Virginia Power plans to purchase capacity and energy from the competitive wholesale power market in the near future. The Company's view of the wholesale power market is that capacity and energy will be available at reasonable prices for at least the next few years.

Virginia Power's estimated construction costs for CC units and pulverized coal units are similar to those estimated by the South Carolina utilities. However, Virginia Power's estimated construction cost for CT units ($203 per Kilowatt) is significantly lower than that used by any of the South Carolina utilities. The average CT construction cost used by the South Carolina utilities is $358 per Kilowatt.

3. Environmental

There is no mention of environmental consequences in Virginia Power's IRP.

The company utilizes PROSCREEN II and PROVIEW for capacity expansion analyses, ECVIEW for emissions compliance and the PROSYM/MULTISYM models for regional market price forecasts.

The appendix to Virginia Power's IRP contains a large number of data tables that appear to have been designed by the Virginia State Corporation Commission. A similar methodology for South Carolina would guarantee that comparable data was supplied by each of the South Carolina utilities. This would ease the burden of evaluating the IRPs, extracting data from the IRPs and comparing and contrasting the IRPs.

4. Relevance to South Carolina

Virginia Power's IRP filing reflects specific requirements made by the Virginia PSC. Although the IRP appears to be lacking certain items, such as environmental impacts, the information provided is very detailed and specific. Like the South Carolina utilities, Virginia Power also states that over the next few years they are planning to rely on capacity purchases to meet their planning needs. Once again, this leads to the question that if all utilities in the Southeast plan to rely on capacity purchases, will enough capacity be built in time to meet growing capacity needs?

D. Baltimore Gas & Electric Company

The 1996 IRP for Baltimore Gas & Electric (BG&E) covers the time frame, 1996 – 2001. The reason for this short time frame was a pending merger with Potomac Electric Power Company to form Constellation Energy Corporation.

The elements of BG&E's resource plan through the year 2001 include a mix of company-owned generation, short- and long-term capacity purchases, as well as demand side resources.

1. Demand-Side Management

BG&E's DSM resources cover a broad base of residential, commercial, and industrial programs designed to reduce both peak demand and energy consumption. The estimated 1996 DSM program contribution to peak demand reduction is made up of these types of programs:

- 69% Peak clipping.
- 10% Load shifting
- 21% Conservation

DSM Types	Residential	Commercial and Industrial
Peak Clipping	A/C Energy Saver Switch	A/C Energy Saver Switch
	Water Heater Energy Saver Switch	Curtailable service
Load-Shifting	Time-Of-Use Rates	Time-Of-Use Rates Cool Storage
Conservation	High-Efficiency HVAC EnergyWise Conservation Home Improvement	Efficient Lighting Comprehensive Comm. Constr. Gas Air Conditioning High-Efficiency HVAC Motors and Compressors Industrial Audits

The BG&E IRP states that its existing DSM programs are estimated to further reduce peak load by 171 MW from 1995 levels by 2001. However, there is no mention of any new DSM programs being introduced into the resource mix.

2. Generation

BG&E's existing generation capacity portfolio is comprised of the following mix: 25% nuclear, 39% coal, 13% oil, 11% gas, 9% long-term purchases, and 3% short-term purchases. BG&E projects a need for 60 MW of capacity by the year 2000 growing to 279 MW by the year 2001. They plan to acquire these resources in the competitive bulk-power market since it is recognized that a surplus of generation capacity currently exists within the Mid-Atlantic Area Council region and is available at attractive prices. BG&E does not expect the surplus of generation capacity to be exhausted in the near future but is developing a Request for Proposals for short-term capacity should the need arise.

3. Environmental

SO2 Emission Compliance Strategy

BG&E owns two Phase I affected units and is a joint owner of two other Phase I affected units. They have made modifications at the two units they own to allow for the use of lower sulfur coals. Scrubbers were installed at the jointly owned units. This will allow BG&E to accumulate a surplus of 50,000 to 70,000 emission allowances by the end of Phase I. BG&E estimates that during Phase II they will not have enough allowances to meet their limits, so they plan to either switch to lower sulfur coal, or purchase allowances.

NOx Emission Compliance Strategy

BG&E is part of the Northeast Ozone Transport Region and therefore is required to install Reasonably Available Control Technology (RACT) to reduce NOx and volatile organic compounds which they have completed. However, they expect stricter NOx emission reductions to be forthcoming and have identified a tentative plan of installation of LNB technology at several plants.

4. Relevance to South Carolina

BG&E's IRP filing was limited in that it was very short. However, BG&E did express some similar themes that should be noted by the South Carolina utilities. As with many other utilities, they plan to acquire short-term resources by purchasing power in the competitive bulk-power market. However, BG&E acknowledges that they are developing a Request for Proposals for short-term capacity should the need arise. It would be advisable for the South Carolina Utilities to develop such a Request for Proposals as well.

E. Northern Indiana Public Service Company

The Northern Indiana Public Service Company's (NIPSCO) 1996 IRP covered the period 1997 – 2017.

1. Demand-Side Management

For this IRP, NIPSCO established an objective of using the RIM test as their criterion for adopting new DSM programs. However, based on the DSM programs NIPSCO evaluated, none passed the RIM test therefore no new DSM programs were incorporated into the resource plan.

2. Generation

NIPSCO evaluated supply-side options using the PROSCREEN II software.

At the start of the IRP, NIPSCO's existing capacity mix was as follows:

- 99.4% steam
- .5% hydro
- .1% gas turbines

Northern Indiana considered the following supply-side technologies:

Conventional Pulverized Coal	Atmospheric Fluidized Bed Combustion
Pressurized Fluidized Bed Combustion	Coal Gasification Combined Cycle
Combustion Turbine	Fuel Cell
Geothermal	Solar-Photovoltaic
Wind Turbine	Municipal Refuse-Fired
Biomas/Wood-Fired	Alternate Fuel Co-Firing
Nuclear-Fueled	Battery Energy Storage
Pumped Hydro Energy Storage	Compressed Air Energy Storage
Superconducting Mag Energy Storage	Peaking Power Purchase
Peaking Power Sale	Peaking Power Purchase
Firm Power Sale	Firm Power Purchase

Supply side technologies were evaluated and analyzed to determine their viability as resource options in the IRP process. Each alternative was examined relative to three primary considerations. The technology was to be compatible with the following:

- The needs of the Northern Indiana system.
- Any constraints of the Northern Indiana system.
- The financial objectives of Northern Indiana.

The three technologies that met the necessary criteria were single cycle CT, CC, and CT/CC conversion units.

NIPSCO's final 1996 IRP required the addition of 85 MW CT units in 2004, 2006, and 2012. It required the addition of 160 MW CC units in 2008, 2011, 2014, and 2017.

3. Environmental

The NIPSCO IRP Report did not mention that they had performed any environmental analysis.

4. Relevance to South Carolina

NIPSCO's IRP filing also was lacking in certain items, such as environmental impacts. NIPSCO'S plan confirms that CC and CT units are the preferred generating unit capacity additions being selected by utilities across the country.

F. Summary

The IRP process has been implemented in a variety of ways in the 35 states that have IRP requirements. However, it is apparent from the analysis of the IRPs of other states that several features could be implemented in South Carolina to improve the overall process. These include the following:

1. **An approval process for IRP and modifications to the IRP** – Where no approval process is required, the filed IRP essentially becomes an informative document only, and the process is not necessarily taken as seriously as possible by the utility. The utility is free to modify the IRP at any time, without explanation. The filed IRP represents only a snapshot of the utility's plans at some moment in time, not a firm plan that will be followed. This is especially a problem if agreement is reached with the PSC or another interested party to modify a filed IRP. Later, if the utility chooses to ignore the modification, then the earlier effort to modify the IRP serves no purpose. As an example, suppose environmental interests succeed in requiring SCE&G to include additional DSM programs in its IRP and at a later date, SCE&G simply ignores the new DSM programs. Effectively, nothing has been accomplished in this process.

2. **PSC Staff involvement in the approval process** – The states with effective IRP processes have close cooperation between the PSC Staff and the utilities. A significant amount of data that must be reviewed by Staff to verify the results of an IRP. Without close cooperation between Staff and the utility, it is unlikely that problems concerning the large amount of shared data can be resolved.

3. **PSC Staff ability to perform IRP modeling** - The PSC Staff (or the staff of the body responsible for approval of the IRPs) must have access to IRP computer models and the ability to use these models. Otherwise, Staff is essentially powerless to fully analyze the filed IRPs and is unable to develop viable alternative IRPs. Without the ability to develop viable alternative IRPs, the process becomes one of simply accepting whatever the utilities file within their IRP.

4. **Detailed IRP filing requirements** – The best IRP filings from the states reviewed were those in which the Staff or PSC had developed detailed filing requirements. Currently, the South Carolina utilities use the PSC IRP requirements simply as guidelines. With more specific filing requirements, each company would know clearly what is expected and could likely reduce the time required for the development of their IRP. Also, with this change, more useful comparisons could be made from one company to the next

V. Recommendations

The existing IRP process provides extremely important information to the public and regulators. The following recommendations are based on the underlying assumption that in the immediate future, utilities will continue to be regulated and should therefore, still follow the IRP filing requirements. These recommendations suggest improvements that will strengthen the IRP process that is in place today. The next section of this report discusses the role of Integrated Resource Planning, if and when the electric industry in South Carolina becomes fully deregulated.

1. **Continuation of the Integrated Resource Planning process** – Until and unless deregulation is <u>fully</u> implemented in South Carolina, at a minimum, the Integrated Resource Planning process should be continued as it exists now. The IRP process provides extremely useful information to the public and regulators to ensure that utilities are planning new resources in a least-cost manner, and in a way that addresses public concerns about the environment, renewable technologies, DSM, and level of risk. The fact that some of the utilities in South Carolina have recommended a "go slow" approach to deregulation only reaffirms the need to continue the Integrated Resource Planning Process as it exists now. While utilities exist as monopolies, it is inconsistent for them to recommend this "go slow" approach to deregulation and also to recommend a reduction in the IRP filing requirements.

Recommendation: Until and unless deregulation is fully implemented in South Carolina, the Integrated Resource Planning process should be continued in its current form.

2. **IRP Approval Process -** There currently exists no requirement for approving an IRP or approving modifications to an existing IRP. Without an approval process, the IRP serves as a process that only informs the public and regulators about the utilities current plans, which can be changed at any time. The process will provide more value if regulatory approval is required for both initial IRPs and any modifications to the IRPs. This is not to say that utilities should be prevented from changing their plans, but that they should be required to substantiate the reasons for making changes. All stakeholders, including at least the ratepayers, stockholders, the State Energy Office, and the PSC Staff, should have a voice in the approval process.

Recommendation: Each utility should be required to obtain approval for its IRP and any subsequent modifications to its IRP. Customers should be allowed to participate in the approval process.

3. **DSM Implementation -** With the exception of CP&L, the South Carolina utilities have not implemented a meaningful amount of DSM programs. The achieved DSM results of SCE&G, Duke and Santee Cooper are well below national averages.

Certainly it is true that avoided capacity costs have fallen and that utilities must be careful to avoid rate increases as more competition in the industry nears, but other utilities have shown that significant DSM savings can still be achieved without harmful rate impacts.

Recommendation: **SCE&G, Duke and Santee Cooper should be required to meet the national average DSM savings (on a percentage basis) in both peak demand savings and energy savings using DSM programs that do not cause rates to increase.**

4. **Load Building Programs** - Many types of DSM programs exist, including conservation, load shifting, dispatchable load control etc. Clearly, programs that are packaged as DSM but result in an increase in peak demand and build energy requirements are marketing programs, and should not be classified as DSM. While marketing programs certainly help the profitability of a utility, they provide exactly the opposite results that DSM programs are intended to provide.

Recommendation: **Require utilities to clearly identify whether their programs are DSM or marketing programs.**

5. **Expansion Plans Promoting Environmental Policies** - Although several of the utilities discussed resource plans under assumed carbon taxes, none of the utilities produced a full IRP based upon the monetization of environmental externalities. This situation makes it virtually impossible for regulators and customers to assess whether the additional cost imposed by monetization would be worth the improvements in air quality.

   The South Carolina IRP regulations require that each utility provide this information, yet they have failed to do so. This is not to say that the utilities should adopt an IRP that is based on the monetization of environmental externalities, only that each utility should provide, in its IRP filing, at least two full IRPs – one that is the utility's preferred IRP and one that is an IRP developed with the monetization of environmental externalities. Both the supply-side and the demand-side plan should be allowed to change based on monetization of externalities. Full details should be provided concerning the levels of emissions under the two plans. This will allow all stakeholders to weigh the costs of additional emission reductions (the cost difference between the two plans) against the gain in air quality.

   To avoid unnecessary complications due to differing levels of monetization, it is also recommended that the Commission select the values to be used by all utilities when monetizing environmental externalities. This will allow for a consistent comparison of the plans of all the utilities.

Recommendation: **The utilities must develop and include in the IRP filings both their preferred IRP and a full IRP that is based upon the monetization of environmental externalities at values set by the Commission.**

6. **IRP Reporting Requirements** - The information provided in the reports varies greatly among the IRPs filed. This problem makes the consistent comparison of the IRPs difficult. The problem would be corrected if the IRP rules specified in more detail the data that must be included in the IRP filings. It would also be useful to the utilities so that in writing their IRP report, they know what their target is. The following information is either inconsistently provided or not provided at all:

- Avoided capacity and energy costs for DSM analysis
- A description of the development of avoided costs for DSM analysis
- A separation of information provided regarding existing DSM programs versus potential new DSM programs
- A complete list of all new DSM programs that were considered
- Cost assumptions for potential DSM resources
- Penetration assumptions for DSM resources
- KW and KWh impacts for all DSM resources considered
- Cost assumptions for potential supply-side resources
- Unit characteristic data for all potential supply-side resources
- Expected levels of emissions under the potential plans
- Total costs of all potential plans
- Generating unit capacity factors for perhaps the last study year
- Fuel cost assumptions

Recommendation: **The Commission should specify the data required to be provided in an IRP filing by the utilities.**

7. **IRP Task Requirements** - In addition to requiring each utility to provide common results as described in Recommendation 5, each utility should be required to perform specified standard tasks as part of their IRP. For example, some of the utilities clearly did a superior job evaluating Risk as part of their IRP, while others did little Risk Analysis at all. Some did more extensive environmental examinations, such as considering how their expansion plan would change if a carbon tax was imposed. At the start of each round of the IRP, the commission should specify standard tasks that each utility should perform.

Recommendation: **The Commission should develop a list of IRP tasks (such as Risk Analysis) that each utility is required to perform as a part of their IRP.**

7. **Computer Models** - Each of the utilities filing IRPs used a different IRP computer model. This adds a layer of complexity to the analysis and comparison of the IRPs, especially for Staff. This problem would be avoided if all the utilities provided data in a form compatible with an IRP computer model the Staff could use.

Recommendation: **The Commission should require that each utility provide all computer modeling data in a form compatible with the IRP computer model utilized by Staff.**

8. **Share Best Practices** - Since the Commission is concerned with minimizing rates across the State, the Commission should determine the best practices each utility utilized in their IRP and promote those to the other utilities. For example, if one utility pursued better DSM programs, or conducted a better risk assessment, then that information should be made available to the other utilities.

Recommendation: **Staff should select the best practices from the filed IRPs and make recommendations to the other utilities to consider those practices.**

9. **Master list of Supply and Demand-Side Options** - The array of demand-side and supply-side options considered by each utility varied considerably, and several options that have proven successful (such as residential load control) were not considered by all the utilities. This problem would be avoided if Staff, in cooperation with the State Energy Office, developed a master list of options that each utility was required to consider.

Recommendation: **Staff and the State Energy Office should develop a master list of demand and supply-side options that each utility must consider in its IRP development.**

Once again, the above recommendations are appropriate for a regulated utility environment and apply during the transition period as well. The next section considers the issue of how IRP should be modified in a deregulated environment.

VI. Recommendations for the Future

The momentum to deregulate the electric industry has been building for a number of years. Legislation enabling full retail competition for electricity has now been passed in ten states. Several states have already tested the waters through pilot programs and now Montana, Pennsylvania, and certain states in New England, including Massachusetts, Rhode Island and New Hampshire are on the threshold of full retail competition. California has begun its "deregulation experiment" by allowing full access to all customers as of April 1, 1998.[60]

The move to deregulation in the Southeastern states is not as imminent as in the Northeast and West. However, hearings on deregulation have been held in Louisiana, Mississippi and Virginia. The Georgia PSC has initiated a series of dockets that could lead to a restructured electric industry by the year 2000. Even though electric rates are generally low in the Southeast, customers have indicated a preference for choice.

In South Carolina, ElectricLite, by advertising a claimed ability to provide electric service at a 20% savings, has created a stir that may lead to deregulation in the next few years. Bills have been proposed in the legislature and the PSC issued a "Proposed Electric Restructuring Implementation Process" on February 3, 1998.

The following sections address the issue of whether an IRP process is appropriate in a deregulated utility environment.

A. IRP

Looking back, has the IRP process served a useful purpose within the utility industry?

The answer to this question is unquestionably yes. The fact that the cost of producing energy today has fallen dramatically can be attributed to a number of factors, not the least of which is the impact that the IRP process has had on developing better resource plans. With the IRP process, imprudent utility capacity addition decisions have virtually been eliminated. To some extent the falling costs of production have come about through careful evaluation of expansion plan alternatives that occurs as part of the IRP process. It has caused utilities to better analyze the specific characteristics of their generating systems, and has provided a useful forum for utilities to clearly articulate to the public how those features influence their resource acquisition plans.

Just as the NASA space program has brought about the commercialization of many technologies that influence our daily lives, so too has the IRP process influenced the creation of an entire energy services industry related to providing DSM services. As

[60] As it is commonly referred to by market participants in California.

deregulation nears, companies have sprouted up all over the country offering customers the opportunity to reduce their costs using techniques that have been made more readily available as a result of having an IRP process. Performance based contracting is one example of this type of service.

Renewable technologies have also been promoted as a part of the IRP process. Although still expensive, these technologies have moved further along than anyone would have expected in terms of a reduction in cost, especially with photovoltaics and wind technologies. An IRP process serves to focus attention on these technologies, even if they are found to be more expensive than other options available to utilities.

What may be the role of Integrated Resource Planning in a deregulated electric utility industry?

In a deregulated utility industry, there are additional reasons for considering an IRP planning process. One of the most important planning issues (which is almost taken for granted under the current regime) is to ensure a reliable supply of capacity. This has been taken for granted because under a regulated scenario, utilities have rarely failed to build the proper amount of capacity to meet the forecasted need.

Advocates proposing total free market principals believe the market will drive the need for new generating resources and demand-side resources. These proponents of competition claim that the market is the only appropriate driver for the selection and timing of additional resources to meet load growth.

Before these notions are tested in a fully deregulated world, it is impossible to know how well they will perform. It is not obvious that the market alone will cause the addition of sufficient generating resources to meet load growth at the time capacity is needed. Certainly, many merchant plants have been announced in areas of the country that are experiencing very high electric rates, but there is no assurance that merchant plants will also be built, close to the time of need, in areas where rates are much lower, as in the Southeast. It may be that, under deregulation, the market will not provide additional resources until rates are sufficiently high.

In its move towards deregulation, Wisconsin is being very cautious about letting the market decide when to make capacity decisions, out of fear of having a repeat of the reliability problems experienced in the summer of 1997. In New York, where an Independent System Operator (ISO) is being considered, an independent reliability board has been proposed to establish standards concerning operational and planning reliability. Texas is also considering an ISO, and there have been discussions concerning the state having responsibility for publishing load forecast information to inform developers of emerging capacity needs.

The following quote was taken from the Georgia PSC's recently published Guiding Principles for the restructuring of the electric industry in Georgia:

> Reliable, safe and adequate electric service is essential and must be maintained at current or improved levels. The state and federal regulatory bodies should have the necessary authority to ensure that electric service is consistent with accepted industry-wide planning and operating standards and that long-term and short-term reliability is assured.

From the Pennsylvania electric deregulation legislation (House Bill No. 1509) comes this statement:

> In regulating the service of electric generation suppliers, the Commission shall impose requirements necessary to ensure that the present quality of service provided by electric utilities does not deteriorate, including assuring that adequate reserve margins of electric supply are maintained ...

Rhode Island apparently plans to continue to require IRP-like filings from the energy providers in that state, as shown in the following quote from the restructuring legislation in that state:

> Filing by electric companies. -- Every electric company whose total annual sales of electric energy in the preceding calendar year exceeds twenty million kilowatt hours shall submit every two (2) years to the public utilities commission a long-range energy plan for the ten (10) year period subsequent to the date the plan is submit, and shall apprise the commission in the interim of any changes which substantially affect the plan. The plan shall include the company's annual peak-load forecasts, annual energy forecasts, proposed generating facilities, and proposed major transmission lines (69 kilovolts or over). The plan shall include information on demand reduction measures, conservation and load management programs, cogeneration, and small power production based on renewable resources. The filing shall include assumptions and methodologies used by the company in formulating the plan.

One function of an IRP's role in a restructured electric utility industry is to assure that enough capacity will be developed in a timely manner. In a deregulated environment a statewide IRP should be performed to make sure that an adequate capacity needs assessment is performed.

Second, a statewide IRP performed under deregulation will also promote competition within the state. By publishing the needs assessment, more suppliers will be made aware of the opportunity to provide for the needs of South Carolina's customers, and this will ultimately translate into lower costs to the consumer.

Third, looking beyond the issue of capacity adequacy, it is difficult to conclude that the market will always provide the "optimal" mix of new resources for South Carolina. The "optimal" mix must consider (at a minimum) total forecasted load growth, risk level, environmental impacts, DSM impacts and total costs. Without direction, it does not seem reasonable that the market will properly assess all the implications of resource selection that are now included in the IRP process. What is also clear is that the market approach will result in a resource plan that has a much shorter focus. A statewide IRP will focus attention over a longer term horizon, and will ensure that appropriate information is disseminated into the market place, so that a more optimal mix of resources can be built.

Finally, environmental planning has been and will continue to be a way of life for utilities. By performing a statewide IRP, guidance to the market can be provided to suggest ways in which environmental concerns can be addressed so that economic and societal environmental costs to all South Carolina consumers can be minimized.

Certainly information will have to be obtained from the players in the market. Distribution Companies, Load Aggregators and Marketers will have to make information available regarding load forecasts. Energy suppliers will have to provide data regarding generating units. Currently regulated utilities insist that the data required to develop IRPs will become valuable, competitive information, and they are less willing to supply that information, even as deregulation approaches. There is some truth to these claims, although not all of the data in an IRP can be viewed as having value to potential competitors. In any case, if the PSC Staff and the State Energy Office are provided data under a confidentiality agreement, the problem should be avoided.

It is also argued by the existing regulated utilities that, if the utilities are to be at risk for generation, rather than guaranteed recovery of generating costs, the utilities must be allowed to procure generation absent any regulation or oversight. Again, there is merit to the argument, but there are also remaining problems. Provisions will have to be made for a "default" provider, or provider of last resort – the utility that is designated to provide power to those customers that do not wish to select a provider and to provide for shortfalls. Surely some oversight or regulation is required to ensure that the default provider procures wholesale resources in a reasonable manner. Since the default provider will most likely be a regulated utility distribution company, the default provider should be required to work with the state to develop the statewide IRP.

Recommendation **Should South Carolina deregulate its electric industry, the PSC Staff and the State Energy Office should develop a statewide IRP to ensure the continued reliability of electric supply and to monitor the environmental impacts of new and existing generating sources.**

B. Energy Information Disclosure and Renewables

Experience with pilot programs in other states has shown that, when offered a choice, many ratepayers will elect to pay higher electric rates to support the development of renewable resources. Also, power marketers in states that are on the verge of retail competition have found that offering a mix of resources that includes significant amounts of renewable energy can provide a marketing edge. As a part of deregulation, energy providers should be required to reveal the amount of renewable energy and the amount of emissions produced by the generating capacity used to serve customers. As a result, retail competition would further encourage the development of clean, renewable technologies.

Recommendation **The State of South Carolina should institute an energy information disclosure requirement for suppliers to provide to their customers which reveals the amount of renewable generation utilized. This will have the benefit of providing information to the market that the market can use to decide if renewable technologies are desirable. Green marketing programs would logically arise from customer demand stimulated by this policy.**

VII. Conclusions

The existing IRP process offers value to customers and regulators within South Carolina by providing information explaining the utility's decision-making process for developing future resource expansion plans.

Many resource planning issues are considered as part of the IRP process including:

- Load growth projections
- Existing resource mix (both supply-side and demand-side)
- New DSM program evaluation
- New generation unit evaluation
- Environmental Impacts
- Risk Analysis

Because regulators and customers are provided this information, they are able to influence the process of selecting the best resources for their service territory.

While IRP studies generally exhibit many of the same general characteristics, there are some differences in the ways that utilities approach the study and in the ways that regulatory oversight is applied in each state. The process in South Carolina has been one in which a set of filing requirements have been established by the Public Service Commission and each utility has been left to freely interpret the requirements. Once filed, the utilities have effectively met the requirements without a formal approval process being held. Based on the filing requirements that currently exist, the utilities taken as a whole have done a reasonable job performing their IRP studies and communicating their results, especially when comparing the IRPs to those filed in other states. But room for improvement still exists.

Under the assumption that a regulated utility environment will continue to exist into the foreseeable future, the current IRP process should be continued and in fact, should be improved utilizing the recommendations herein. In addition, there is no reason to eliminate or even to reduce the scope of the IRP process during a transition to full deregulation, should that occur. One of the most important recommendations for improvement is for South Carolina to have a regulatory approval process that occurs once IRP reports are filed. This would allow the PSC to establish certain issues of importance for utilities to consider at the onset of the IRP, and would ensure that all of the submitted plans address the issues adequately.

Once restructuring is complete (should it occur), a new form of Integrated Resource Planning should be developed. The PSC Staff and the State Energy Office should collaborate to develop a statewide IRP to ensure continued reliable electric service throughout the state and monitor the environmental impacts of all generating sources.

VIII. Attachment A - The California Standard Cost Effectiveness Tests

$$\textbf{TRC Test} = \frac{\text{Benefit}}{\text{Costs}} = \frac{\text{Avoided Capacity Costs + Avoided Fuel Costs}}{\text{Utility Program Costs + Participants Costs}}$$

Goal is to minimize average total energy bills

$$\textbf{Utility Test} = \frac{\text{Benefit}}{\text{Costs}} = \frac{\text{Avoided Capacity Costs + Avoided Fuel Costs}}{\text{Utility Program Costs + Utility Paid Incentives}}$$

Goal is to minimize utility revenue requirements

$$\textbf{Participants Test} = \frac{\text{Benefit}}{\text{Costs}} = \frac{\text{Participants Bill Reduction + Incentives}}{\text{Program Costs}}$$

Goal is to minimize participating customers costs only

$$\textbf{RIM Test} = \frac{\text{Benefit}}{\text{Costs}} = \frac{\text{Avoided Capacity Costs + Avoided Fuel Costs}}{\text{Utility Program Costs + Utility Paid Incentives + Lost Revenues}}$$

Goal is to minimize average rates

Where:

Avoided Capacity Costs	=	Construction, T&D, and Fixed O&M
Avoided Fuel Costs	=	Operating Costs not incurred due to DSM program
Utility Program Costs	=	Utility Cost to implement program (Admin, etc)
Incentive Payments	=	Incentives paid to the customer
Lost Revenues	=	Revenues lost by utility due to lower KWh sales
Participants Bill Reduction	=	Lower bills due to less KWh consumed
Participants Costs	=	Any Costs participant incurs to participate in DSM

IX. Attachment B - Author Biographies

Philip Hayet
Hayet Power Systems Consulting
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EDUCATION/CERTIFICATION

Registered Professional Engineer in the State of Georgia, 1987
M.S., Electrical Engineering, Georgia Institute of Technology, 1980
B.S., Electrical Engineering, Purdue University, 1979
Cooperative Education Certificate, Purdue University, 1979
Member National Professional Engineering Society

EXPERIENCE

Mr. Hayet has over seventeen years experience in the electric utility industry covering a number of areas including system planning, operations, economic analysis and financial planning. Since the end of 1995, Mr. Hayet has managed his own utility consulting firm specializing in the same utility planning issues.

On a recent assignment, Mr. Hayet addressed the role of Integrated Resource Planning in a restructured utility environment. Part of this analysis included the investigation of software planning models used to analyze utility operations in a regulated versus deregulated environment. On a previous assignment, he helped develop least cost expansion plans for a Southeast Asian Country, using Integrated Resource Planning Modeling techniques. On a project for an Australian client, Mr. Hayet produced market energy forecasts based on a competitive deregulated electric utility market.

Prior to starting his own firm, Mr. Hayet worked for 15 years at The Utilities Division of EDS (formerly known as Energy Management Associates) where he provided consulting services using system planning software models to electric utilities, governmental agencies and private industry. While working at EDS, Mr. Hayet conducted numerous studies in the areas of Generation Planning, Demand-Side Management, Integrated Resource Planning, Load Forecasting, Rate Analysis, Project Finance, Economic Analysis, and Regulatory Support. He is knowledgeable of electric and gas markets in the US and selected foreign countries with both regulated and deregulated structures. Much of the consulting work performed at EDS involved the PROMOD IV and PROSCREEN II software planning tools.

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SPECIFIC EXPERIENCE

1996 to Present: **Hayet Power Systems Consulting, Atlanta, GA**

- Investigated alternative rate-making methods as part of a current rate proceeding
- Performed various assignments for an Australian private power developer helping to analyze power generation opportunities at sites world-wide
- Developed market based energy forecasts for an Independent Power Producer in Australia
- Performed strategic modeling studies to develop Least Cost Expansion plans for Vietnam
- Analyzed the role of IRP in a deregulated electric utility industry

1991 to 1996: **EDS Utilities Division, Atlanta, GA**
Lead Consultant, PROSCREEN Department

- Performed system planning consulting studies including integrated resource planning, DSM analysis, marketing profitability studies, optimal reserve margin analyses, etc.
- Managed a client services team that supported approximately 50 users of the PROSCREEN II electric utility strategic planning software.
- Provided client management direction and support, and developed new consulting business opportunities.

1988 to 1991: **Energy Management Associates (EMA), Atlanta, GA**
Manager, Production Analysis Department

- Served as Project Manager of a database modeling effort to create an integrated utility operations and generation planning database. Database items were automatically fed into EMA's software products.
- Supervised and directed a staff of five software developers working with a 4GL database programming language.
- Interfaced with clients to determine system software specifications, and provide ongoing client training and support

1980 to 1988: **Energy Management Associates (EMA), Atlanta, GA**
Senior Consultant, PROMOD IV Department

- Provided client service support to EMA's base of nearly 100 electric utility customers using the PROMOD IV probabilistic production cost simulation software.

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SELECTED CONSULTING ASSIGNMENTS

Delmarva Power Corporation IRP and Demand Side Management Analysis
This consulting study was performed in order to satisfy multiple regulatory filing requirements that Delmarva had to meet. The study was conducted by performing both a load forecast and load shape analysis, a DSM cost/benefit evaluation, and an Integrated Resource Expansion Plan Study. Results of the study helped to confirm the fact that many of Delmarva's DSM programs were simply not cost effective and provided the basis for canceling the uneconomic DSM programs, and re-focused attention on those programs deemed to be economically feasible.

Australia Competitive Market Assessment
The Southeastern part of Australia has evolved into a deregulated competitive power market. New evaluation tools have been developed to analyze these types of markets, including the Network Economy Model within the PROSCREEN software modeling system. Under an engagement with BHP Power, one of the largest industrial concerns in Australia, the entire Australian competitive market was modeled in order to forecast energy prices over a long term horizon and under numerous conditions. The objective was to determine the rate of return the company could make by building various power projects and earning revenue from the competitive market.

Vietnam BOT Combined Cycle Project
Under another engagement with BHP Power, who is also a player in the international power development market, an analysis of the Vietnamese Power System was performed to determine the minimum requirements necessary to meet the country's power needs over both a short and long term horizon. The major question investigated was how a new 650 MW Combined Cycle unit would be dispatched within the Vietnamese System and how much the energy would be worth to the government.

Florida Power Corporation IRP and Demand Side Management Analysis
The Florida PSC held DSM Goals Hearings, which required all utilities in the state of Florida to file DSM goals, whose benefits had to be justified in the context of an integrated resource plan analysis. As part of the docket, the commission wanted to determine if they should institute an annual statewide IRP filing requirement. Assistance was provided to FPC to use PROSCREEN to perform the IRP study and to analyze over 150 different potential DSM measures. The results were then submitted as part of the filing.

Tokyo Electric Power Company (TEPCO) Survey
In 1995, the Japanese Government signaled their intent to open up the electric utility industry to Independent Power Producers. Consequently, TEPCO wanted to have a better understanding of how US utilities developed avoided capacity and energy payments and the characteristics of purchase power contracts. A survey of 6 US electric utilities was conducted, and a report of the findings was presented to TEPCO in Japan.

Survey of Typical Utility Operations for Kansai Electric
The Japanese Utility Industry has been evolving and the government is investigating various forms of legislation to open transmission access similar to the way that FERC required open access in the United States. As a result, Kansai Electric requested a survey of certain operational utility practices in existence in the US today and how they would be modified in the future under a deregulated environment. More specifically, Kansai was concerned about coordination issues among utilities and independent power producers. Two US utilities were surveyed and a report was written and provided to Kansai Electric.

City of Austin Alternative Resource Analysis
Evaluated alternative resource expansion plans looking at non-traditional technologies such as wind, biomass, small head hydro, photovoltaics, etc. This project was performed at the request of the city council whose citizenry desired to pull out of the South Texas Nuclear Project and to find alternative power generation technologies.

Duquesne Power and Light Company - Marketing Profitability Analysis
Used PROMOD, which is a detailed production cost simulation tool to assess the benefits of various commercial and industrial marketing programs. Conducted an optimal load shape analysis study in order to narrow down the list of potential marketing programs. This project was ahead of its time, before it became popular to perform detailed marketing program analyses.

Various New York Power Pool System Planning Consulting Assignments
Worked on projects for all 7 investor owned electric utilities, including 9 Mile Point 2 Cancellation Studies, Shoreham Cancellation Studies, 9 Mile Point 1 Power Replacement Cost Analyses, New York Power Pool Resource Planning Studies, Marginal Cost Analyses, Long Run Avoided Cost Studies, Co-generation Negotiation, Litigation Support, and Regulatory Support.

PUBLICATIONS

Co-authored and Presented "Evaluation of a Large Number of Demand-Side Measures in the IRP Process: Florida Power Corporation's Experience", Presented at the 3rd International Energy and DSM Conference, Vancouver British Columbia, November 1994

Co-authored "Impact of DSM Program on Delmarva's Integrated Resource Plan", Published in the 4th International Energy and DSM Conference Proceedings, held in Berlin, Germany, 1995

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EDUCATION: Master of Science, Applied Mathematics, Georgia Institute of Technology, 1976
Bachelor of Science, Applied Mathematics, Georgia Institute of Technology, 1974

PROFESSIONAL MEMBERSHIP: Institute of Electrical and Electronic Engineers

EXPERIENCE:

Mr. Evans recently joined Slater Consultants – a group of nine professionals, including Kenneth J. Slater, Mark D. Younger and J. Mark Shell. He has served the electric power utility industry for seventeen years. His primary areas of expertise include market price forecasting, integrated resource planning, the analysis of purchased power, system operations, interruptible rates, the optimal scheduling of generator maintenance and the computer simulation of electric power systems. As an expert witness in these areas, Mr. Evans has submitted testimony before the FERC, the Georgia Public Service Commission, the Pennsylvania Public Utilities Commission, the South Dakota Public Utility Commission, the Michigan Public Service Commission and the Arkansas Public Service Commission. In addition, he has assisted in the development of expert testimony filed before the Public Utility Commission of Texas, the Michigan Public Service Commission and the New Jersey Board of Public Utilities.

Specific Experience Includes:

1997-Present Slater Consulting (770) 499-0930

Development of the estimated damages caused by imprudent outages of a nuclear generating unit.

1989-1997 GDS Associates, Inc. (770) 425-8100

Mr. Evans served as a principal and the Manager of the System Modeling group, where he was responsible for performing analyses, providing expert testimony and developing customized software. He is an expert in the use of the industry standard computer models PROMOD III, PROSCREEN II, PROVIEW, MAINPLAN, CAT II and ENPRO. A sampling of representative assignments follows:

Tenaska, Air Liquide & Tenneco - Developed forecasts of market clearing prices for electricity in the ERCOT region.

GEMC - Produced a forecast of market clearing prices for electricity in the SERC region and estimated stranded costs.

Central Virginia Electric Cooperative - Designed, developed and installed software to allow the Cooperative to purchase economy energy in an optimal manner on a daily basis.

City of Grand Island, Nebraska - Developed the initial Integrated Resource Plan for the City of Grand Island.

Georgia PSC - Evaluated the 1995 Integrated Resource Plans filed by Georgia Power and Savannah Electric. Developed alternative Integrated Resource plans that were approved by the Commission.

Nucor Steel - Audited the bills for electric service for the Nucor-Hickman Steel Mill.

Nucor Steel - Testified before the Arkansas PSC concerning the reasonableness of a buy-through clause for interruptible customers.

Nucor Steel - Developed a comprehensive forecast of the likely levels of interruptions of service over the next ten years.

South Dakota Public Utility Commission - Evaluated the rate filing and Integrated Resource Plan filed by Black Hills Power & Light.

Georgia PSC - Evaluated Georgia Power's initial RFP for power, all bids received and Georgia Power's selection process. Testified before the Georgia PSC concerning the reasonableness of Georgia Power's evaluation process and resulting request for certification.

Michigan Attorney General - Performed studies concerning the availability of the Midland Cogeneration Venture and Consumer Power Company's avoided costs.

Michigan Attorney General - Developed estimates of cost reductions due to improved projected fossil performance and changes in cogeneration levels in a Consumers Power rate case.

Pennsylvania PUC - Testified concerning the capacity needs of a Pennsylvania utility and the appropriate avoided costs due potential cogeneration projects.

Golden Spread Electric Cooperative - Developed detailed historical reconstructions of five years of hourly operations of a major Texas utility to illustrate the penalties arising to wholesale ratepayers as a result of off-system sales.

Sam Rayburn G&T - Designed, developed and implemented a PC-based software system to facilitate daily load forecasting, optimal resource scheduling and inadvertent accounting in a user-friendly fashion.

Tex-La Electric Cooperative - Designed, developed and implemented a similar software system for daily load forecasting and optimal resource scheduling. This application also included the development of an optimization process which maximizes the total economy energy scheduled while adhering to limitations on load factor and the number of hourly changes.

PG&E-Bechtel Generating Company - Assisted this NUG developer in forecasting the dispatchability of a project and estimating likely costs in a power bidding solicitation.

1980-1989 Energy Management Associates, Inc. - now known as EDS Utilities Division

While with EMA, Mr. Evans performed product development, maintenance programming and client support on the three major products marketed and developed by EMA - PROMOD III, PROSCREEN II, and MAINPLAN. He is extremely well-versed in the development of databases for these tools and in applying these tools to particular studies.

As MAINPLAN Product Manager (1985-1989), Mr. Evans supervised and directed the development, maintenance, and client support for MAINPLAN - the software package that is the industry leader in the area of generating unit maintenance scheduling. The client base for MAINPLAN grew from two clients to over thirty clients during his involvement. Also during his tenure, a chronological production costing model was added to MAINPLAN. This highly detailed model has been used to evaluate interchange opportunities, the cost of forced outages, short-term fuel requirements and unit commitment strategies.

Publications:

Backcasting - A new computer application can determine historical truth for utilities that must refute damage claims, Fortnightly, October 1, 1993.

"Avoiding and Managing Interruptions of Electric Service Under an Interruptible Contract or Tariff", Industrial Energy Technology Conference, April, 1995.

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